Capital Power Corporation
5th Floor, TD Tower, 10088 - 102 Avenue
Edmonton, AB T5J 2Z1

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Capital Power reports first quarter 2011 results

EDMONTON, Alberta – Capital Power Corporation (Capital Power, or the Company) (TSX: CPX) today released its results for the quarter ended March 31, 2011. Normalized earnings attributable to common shareholders, after adjusting for one-time items and fair value adjustments, was $11 million, or $0.33 per share, in the first quarter of 2011, compared with $11 million, or $0.51 per share, in the comparable 2010 period. Funds from operations, excluding non-controlling interests in Capital Power Income L.P. (CPILP), totaled $78 million in the first quarter of 2011, up 10% from $71 million in the first quarter of 2010.

"The decline in normalized net income in the first quarter of 2011 compared with the corresponding period in 2010 was primarily attributable to lower margins realized on the merchant trading portfolio," said Capital Power's President and CEO, Brian Vaasjo. "With the shutdown of two large coal plants in the region and colder-than-average weather in Alberta, spot prices increased in the quarter. However, the Company's average realized price for the Alberta commercial portfolio decreased from approximately $67/MWh in the first quarter of 2010 to approximately $64/MWh in the corresponding period in 2011 as a more significant portion of the Company's Alberta portfolio was sold forward at lower prices. If forecasted Alberta power prices remain in the low-$60/MWh for the balance of the year, we expect our normalized earnings per share to be approximately $1.40."

"Overall, we were very pleased with the performance of our assets", added Mr. Vaasjo. "Average plant availability, excluding CPILP plants, remained strong at 93% and electricity generation reached 3,590 gigawatt hours. The quarter was also highlighted by the announcements of agreements to acquire three New England power generation facilities, located in Tiverton, Rhode Island, Rumford, Maine and Bridgeport, Connecticut. These facilities cumulatively represent approximately 1,069 megawatts of production and are expected to contribute $34 million to $38 million in earnings after depreciation expense and before financing and income tax expenses in 2011. We are very excited about putting together this great hub of assets in one of our key target markets."

Operational and Financial Highlights(1)	**Three months ended March 31** (unaudited)	
(millions of dollars except per share and operational amounts)	**2011**	**2010**
Electricity generation (GWh)	**3,590**	3,529
Generation plant availability (excluding CPILP plants) (%)	**93%**	93%
Revenues and other income	**458**	501
Gross income	**167**	217
Earnings before interest, taxes, depreciation and amortization (EBITDA)(2)	**82**	169

Normalized earnings attributable to common shareholders(2)	**11**	**11**
Normalized earnings per share(2)	**$0.33**	$0.51
Net income attributable to shareholders	**3**	12
Earnings per share	**$0.06**	$0.55
Dividends declared per share	**$0.315**	$0.315
Funds from operations(2)	**99**	99
Funds from operations excluding non-controlling interests in CPILP(2)	**78**	71
Capital expenditures	**89**	62

(1) The operational and financial highlights in this press release should be read in conjunction with Management's Discussion and Analysis and the unaudited Condensed Interim Consolidated Financial Statements for the three months ended March 31, 2011.

(2) Earnings before interest, taxes, depreciation and amortization (EBITDA), Normalized earnings attributable to common shareholders, Normalized earnings per share, Funds from operations, and Funds from operations excluding non-controlling interests in CPILP are non-IFRS financial measures and do not have standardized meanings under IFRS, and therefore, may not be comparable to similar measures used by other enterprises. See Non-IFRS Financial Measures. Reconciliations of these non-IFRS financial measures to Net income attributable to shareholders, Earnings per share and Cash provided by operating activities are included in the Company's Management's Discussion and Analysis dated April 28, 2011, which is available under the Company's profile on SEDAR at www.SEDAR.com.

Significant Events

$232 million common share offering

In March 2011, the Company issued and sold 9,315,000 common shares at a price of $24.90 per share to a syndicate of underwriters co-led by TD Securities Inc. and CIBC World Markets Inc., for gross proceeds of $232 million less issue costs of $9 million. The sale included an initial sale of 8,100,000 common shares on March 17, 2011 followed by the sale of an additional 1,215,000 common shares on March 28, 2011 pursuant to the exercise of an over-allotment option granted to the syndicate of underwriters. The net proceeds from the common share offering were used to repay a portion of the outstanding indebtedness under the Company's credit facilities. The Company expects to draw down on its credit facilities to finance the acquisitions of three New England plants discussed below.

Acquisition of two New England power plants

In February 2011, Capital Power LP (CPLP) entered into an agreement to acquire two generating facilities from Brick Power Holdings LLC, one facility located in Tiverton, Rhode Island (Tiverton) and one facility located in Rumford, Maine (Rumford). Both plants are natural gas-fired combined cycle power generation facilities serving the New England region in the U.S. Northeast, and have a maximum combined capacity of 549 MW. The Company expects the transaction to close on April 29, 2011 at a purchase price of US$315 million subject to working capital adjustments and other closing adjustments.

Both plants are merchant facilities and sell their output into the New England Power Pool (NEPOOL). The plants began commercial operations in 2000 and have similar design configurations that utilize a single fuel GE 7FA power island. The Company commissioned and operates similar technology at the Frederickson power facility in Washington State.

Tiverton and Rumford supply electricity to the New England Independent System Operator (ISO-NE). Both plants are exempt wholesale generators and have Federal Energy Regulatory Commission (FERC) authorization to sell capacity, energy, and ancillary services at market-based rates. The plants are operated as mid-merit generation units and sell their outputs on an hourly basis into the

NEPOOL. The NEPOOL serves six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont which contain approximately 14 million people and over 6 million households and businesses. The NEPOOL is subject to FERC jurisdiction and has more than 400 participants, over 8,000 miles of transmission lines, and 13 interconnections to the New York and Canadian power systems. It is one of the most advanced and liquid markets in the U.S. and has a peak demand of approximately 28,000 MW.

Subsequent Events

$300 million debt offering

On April 18, 2011, CPLP completed a public offering of $300 million unsecured medium-term notes. The notes have a coupon rate of 4.6%, payable semiannually commencing on June 1, 2011, and mature on December 1, 2015. The net proceeds of the offering will be used for general corporate purposes including repayment of amounts owing under credit facilities, short-term investment, financing of ongoing capital projects and working capital requirements. The notes have been rated BBB by Standard & Poor's and BBB by DBRS. The offering was made pursuant to CPLP's short form base shelf prospectus dated April 14, 2010 and a related pricing supplement dated April 13, 2011.

Acquisition of a third New England power plant

In March 2011, the Company entered into an agreement to acquire Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport Energy), from affiliates of LS Power Equity Advisors, LLC. Bridgeport Energy is a natural gas-fired combined cycle power generation plant located in Bridgeport, Connecticut, with a nominal capacity of 520 MW. It is an efficient, young, mid-merit generation plant that can maximize energy and ancillary services revenue through operational flexibility.

Under the purchase and sale agreement, CPLP is acquiring one hundred per cent of the equity interests in Bridgeport Energy, LLC. The transaction closed on April 28, 2011 at a purchase price of US$355 million plus working capital adjustments and other closing adjustments.

As part of the NEPOOL, Bridgeport Energy dispatches into the premium Southwest Connecticut Zone of the ISO-NE market, and has historically received payments for energy, capacity and ancillary services. Bridgeport Energy is a modern, efficient plant that has among the lowest heat rates in ISO-NE. The site has adequate space to develop a peaking facility when market conditions warrant.

Bridgeport Energy entered commercial operation in July 1999. It is equipped with two Siemens V84.3A gas turbines, which are the same design as those used at CPILP's facility in Colorado, and produces additional output from two Heat Recovery Steam Generators and one single-reheat condensing steam turbine. Electrical interconnection into the United Illuminating system is made via the Singer 345kV substation, and natural gas is supplied through a lateral to the Iroquois Gas pipeline system. The facility was designed to minimize environmental impacts and utilizes advanced emission control technologies, including selective catalytic reduction nitrogen oxide controls.

The Company expects to permanently finance both New England acquisitions using a combination of debt and equity. It also expects the acquisitions to contribute approximately $51 million - $55 million to EBITDA and to increase depreciation expense by approximately $17 million in 2011.

Following the acquisitions, Capital Power will have added or placed into development approximately 2,000 MW of generating capacity since the Company's July 2009 IPO. The acquisitions demonstrate the Company's commitment to its growth strategy aimed at reaching 10,000 MW of assets by 2020. The acquisitions also provide Capital Power with the foundation for a networked hub of assets in the U.S. Northeast, which is one of the Company's target markets, and contributes to a balanced portfolio of contracted and merchant assets. As relatively young, highly efficient natural gas-fired plants that use proven technologies, these additions to the fleet fit the Company's technology and operating focus.

Analyst Conference Call and Webcast

Capital Power will be hosting a conference call and live webcast with analysts on May 2, 2011 at 9:00

am (ET) to discuss first quarter results. The conference call dial-in numbers are:

(403) 532-8075 (Calgary)
(604) 681-0262 (Vancouver)
(647) 837-0597 (Toronto)
(877) 353-9586 (toll-free from Canada and USA)

Participant access code for the call: 21543#

A replay of the conference call will be available following the call at: (877) 353-9587 (toll-free) and entering pass code 541020. The replay will be available until midnight on June 2, 2011.

Interested parties may also access the live webcast on the Company's website at www.capitalpower.com with an archive of the webcast available following the conference call.

Non-IFRS Financial Measures

The Company uses (i) EBITDA, (ii) funds from operations, (iii) funds from operations excluding non-controlling interests in CPILP, (iv) normalized earnings attributable to common shareholders and (v) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to IFRS and do not have standardized meanings prescribed by IFRS, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, cash flow from operating activities or other measures of financial performance calculated in accordance with IFRS. Rather, these measures are provided to complement IFRS measures in the analysis of the Company's results of operations from management's perspective. Reconciliations of EBITDA to net income, funds from operations and funds from operations excluding non-controlling interests in CPILP to cash provided by operating activities, normalized earnings attributable to common shareholders to net income attributable to common shareholders, and normalized earnings per share to earnings per share are contained in the Company's Management's Discussion and Analysis dated April 28, 2011 for the quarter ended March 31, 2011 which is available under the Company's profile on SEDAR at www.SEDAR.com.

Forward-looking Information

Certain information in this press release is forward-looking within the meaning of Canadian securities laws as it relates to anticipated financial performance, events or strategies. When used in this context, words such as will, anticipate, believe, plan, intend, target, and expect or similar words suggest future outcomes.

Forward-looking information in this press release includes, among other things, information relating to: (i) expectations regarding the use of the proceeds from the common share and debt offerings; (ii) expectations that Bridgeport can maximize energy and ancillary services revenue through operational flexibility; (iii) expectations regarding the purchase price and timing of closing of the Tiverton and Rumford acquisition; (iv) expectations regarding the permanent financing of the New England plant acquisitions using a combination of debt and equity; (v) expectations regarding the impact of the acquisition of the New England facilities on earnings after depreciation expense and before financing and income tax expense, EBITDA and depreciation expense in 2011; (vi) expectations regarding the ability to attain the goal of 10,000 MW of assets by 2020; (vii) expectations that the Tiverton, Rumford and Bridgeport power plants will provide Capital Power with the foundation of a networked hub in the U.S. Northeast; (viii) expectations that the Tiverton, Rumford and Bridgeport power plants will contribute to a balanced portfolio of contracted and merchant assets; and (ix) expectations regarding normalized earnings per share of $1.40 in 2011.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements include, but are not limited to: (i) the operation of the Company's facilities; (ii) power plant availability and dispatch, including Sundance which is subject to an acquired PPA; (iii) the Company's financial position and credit facilities and sources of funding; (iv) the Company's assessment of commodity and power markets, including power prices for 2011; (v) the Company's assessment of the markets and regulatory environments in which it operates; (vi) weather; (vii) availability and cost of labour and management resources; (viii) performance of contractors and suppliers; (ix) availability and cost of financing; (x) foreign exchange rates; (xi) management's analysis of applicable tax legislation; (xii) currently applicable and proposed tax laws will not change and will be implemented; (xiii) currently applicable and proposed environmental regulations will be implemented; (xiv) counterparties will perform their obligations; (xv) renewal and terms of PPAs; (xvi) ability to successfully integrate and realize benefits of its acquisitions; (xvii) ability to implement strategic initiatives which will yield the expected benefits; (xviii) ability to obtain necessary regulatory approvals for development projects; (xix) the Company's assessment of capital markets, common share ownership distribution, and ability to complete future share and debt offerings; (xx) locations of projects and the areas of which they will be developed, including the availability and use of certain optioned lands; (xxi) costs of construction and development; and (xxii) current risk management strategies including hedges will be in place.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such risks and uncertainties include, but are not limited to, risks relating to: (i) operation of the Company's facilities; (ii) power plant availability and performance, including unplanned plant outages at facilities of other market participants; (iii) unanticipated maintenance and other expenditures; (iv) availability and price of energy commodities; (v) electricity load settlement; (vi) regulatory and government decisions including changes to environmental, financial reporting and tax legislation; (vii) weather and economic conditions; (viii) competitive pressures; (ix) construction; (x) availability and cost of financing; (xi) foreign exchange; (xii) availability and cost of labour, equipment and management resources; (xiii) performance of counterparties, partners, contractors and suppliers in fulfilling their obligations to the Company; (xiv) developments in the North American capital markets; (xv) compliance with financial covenants; (xvi) ability to successfully realize the benefits of acquisitions and investments; (xvii) the tax attributes of and implications of any acquisitions; (xviii) the outcome of CPILP's strategic review; and (xix) ability to secure new contracts and terms of such contracts. If any such risks actually occur, they could materially adversely affect the Company's business, financial condition or results of operations. In that case the trading price of the Company's common shares could decline, perhaps materially.

About Capital Power Corporation

Capital Power is a growth-oriented North American independent power producer, building on more than a century of innovation and reliable performance. The Company's vision is to be recognized as one of North America's most respected, reliable and competitive power generators. Capital Power is headquartered in Edmonton, Alberta. Following the close of its recently announced New England acquisitions, Capital Power will have interests in 34 facilities in Canada and the U.S. totaling nearly 4,900 megawatts of generation capacity. Capital Power and its subsidiaries develop, acquire and optimize power generation from a wide range of energy sources.

For more information, please contact:

Media Relations:
Mike Long
(780) 392-5207
mlong@capitalpower.com

Investor Relations:
Randy Mah
(780) 392-5305 or (866) 896-4636 (toll-free)
investor@capitalpower.com

CAPITAL POWER CORPORATION
Interim Report
March 31, 2011

Management's Discussion and Analysis

This management's discussion and analysis (MD&A), dated April 28, 2011, should be read in conjunction with the unaudited condensed interim consolidated financial statements of Capital Power Corporation and its subsidiaries for the three months ended March 31, 2011, the audited consolidated financial statements and MD&A of the Company for the twelve months ended December 31, 2010 and the cautionary statement regarding forward-looking information which begins on page 34. In this MD&A, any reference to the Company or Capital Power, except where otherwise noted or the context otherwise indicates, means Capital Power Corporation, together with its subsidiaries.

In this MD&A, financial information for the three months ended March 31, 2011 and three months ended March 31, 2010 is based on the unaudited condensed interim consolidated financial statements of the Company, which were prepared in accordance with International Financial Reporting Standards (IFRS), and are presented in Canadian dollars unless otherwise specified. In accordance with its terms of reference, the Audit Committee of the Company's Board of Directors reviews the contents of the MD&A and recommends its approval by the Board of Directors. The Board of Directors has approved this MD&A, as of April 28, 2011.

On January 1, 2011, IFRS, as issued by the International Accounting Standards Board, became the Canadian generally accepted accounting principles (GAAP) for the basis of preparation of financial statements for publicly accountable enterprises. The information presented in this MD&A, including information relating to comparative periods in 2010, is presented in accordance with IFRS unless otherwise noted as being presented under previous Canadian GAAP (previous CGAAP) and not IFRS. A discussion regarding the Company's transition to IFRS, including the impact of significant accounting policy choices and the selection of IFRS 1 elections and exemptions, can be found in the IFRS section which begins on page 27.

The Company's outstanding share capital on March 31, 2011 consisted of 40.394 million common shares, 5 million Cumulative Rate Reset Preference Shares, Series 1, 47.416 million special voting shares and one special limited voting share.

The Business

The Company's power generation operations and assets are owned by Capital Power LP (CPLP), a subsidiary of the Company. At March 31, 2011, the Company held approximately 21.750 million general partnership units and 18.524 million common limited partnership units of CPLP which represented approximately 24.8% and 21.1%, respectively, of CPLP, and EPCOR Utilities Inc. (EPCOR) held 47.416 million exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power Corporation on a one-for-one basis) representing approximately 54.1% of CPLP. The general partner of CPLP is wholly-owned by Capital Power and EPCOR's representation on the Board of Directors does not represent a controlling vote. Accordingly, Capital Power controls CPLP and the operations of CPLP have been consolidated for financial statement purposes.

The assets used in the operating business of the Company are primarily held through CPLP and its subsidiary entities. The interests held by the Company outside CPLP are not material to the Company's consolidated operations, assets, liabilities and operating business or the Company's consolidated financial statements and are primarily a consequence of the Company's organizational structure. The primary assets and liabilities of the Company that are held outside of CPLP are:

- The Company's indirect interest in the general partners of the Canadian limited partnerships through which CPLP's Canadian power generation facilities are held, representing an equity interest of 1% or less in each of these partnerships;
- The Company's indirect interest in a subsidiary entity (CP Regional Power Services Limited Partnership) that provides management and administrative services to Capital Power Income L.P. (CPILP) and the Company's Canadian limited partnerships, under various management and operation agreements;

- Future income tax assets and liabilities resulting primarily from the Company's interest in CPLP which, as a limited partnership is not a taxable entity; and
- Certain natural gas customer contracts for which a non-current liability has been recorded on the consolidated balance sheet to reflect the estimated loss in fair value of the contracts which arose at the time of acquisition of these contracts from EPCOR.

These items did not have a material impact on the Company's consolidated revenues, income from continuing operations, or income before income tax expense for the three months ended March 31, 2011 or on the Company's consolidated total assets or total liabilities as at March 31, 2011. CPLP's consolidated revenues, and income from continuing operations for the three months ended March 31, 2011, and consolidated total assets and total liabilities as at March 31, 2011 represent 97% or more of the corresponding consolidated items of the Company.

Financial Highlights

(unaudited, $millions, except earnings per share)	Three months ended	
	March 31, 2011	March 31, 2010
Revenues and other income	$ 458	$ 501
Gross income	167	217
Earnings before interest, taxes, depreciation and amortization (EBITDA)(1)	82	169
Net income	14	92
Net income attributable to shareholders of the Company	3	12
Earnings per share	$0.06	$0.55
Fully diluted earnings per share(2)	$0.05	$0.55
Normalized earnings per share(1)	$0.33	$0.51
Funds from operations(1)	99	99
Capital expenditures	89	62

(1) The consolidated financial information, except for EBITDA, normalized earnings per share and funds from operations, has been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

(2) Fully diluted earnings per share is calculated after giving effect to the exchange of limited partnership units of CPLP (exchangeable for common shares of Capital Power Corporation on a one-for-one basis) held by EPCOR.

Funds from Operations

(unaudited, $millions)	Three months ended	
	Mar 31, 2011	Mar 31, 2010
Funds from operations excluding non-controlling interests in CPILP(1)	$ 78	$ 71
Funds from operations(1)	99	99

(1) Funds from operations and funds from operations excluding non-controlling interests in CPILP are non-IFRS measures. See Non-IFRS Financial Measures.

Funds from operations are cash provided by operating activities, including interest and current income tax expense rather than interest and income taxes paid, and excluding changes in working capital.

The increase in funds from operations excluding the non-controlling interest in CPILP for the first quarter of 2011 compared with the corresponding period in 2010 was primarily due to lower current income tax expense, partly offset by lower EBITDA (earnings before interest, taxes, depreciation and amortization) excluding unrealized fair value changes. In the first quarter of 2010, current income tax expense primarily related to income taxes on 2009 partnership income which became payable in 2010. In the first quarter of 2010, funds from operations reflected higher than anticipated EBITDA, excluding unrealized fair value changes, from the Alberta commercial plants and portfolio optimization as low spot power prices resulted in higher realized prices on the trading transactions that settled in the quarter.

Funds from operations include CPILP's funds from operations, which were reduced in the first quarter of 2011 by current income taxes which were a result of SIFT legislation that became effective January 1, 2011. Under the new legislation the partnership's taxable income is taxed at the partnership level rather than in the hands of the partnership's unitholders. CPILP expects the current period's accrued estimate for these income taxes to reverse in the second or third quarter of 2011.

Since the non-controlling interests in CPILP's funds from operations were approximately 70.6% (at March 31, 2011) the Company uses funds from operations excluding non-controlling interests in CPILP to provide a more meaningful measure of the Company's operating cash flows. See Non-IFRS Financial Measures.

Normalized Earnings and Normalized Earnings per Share

(unaudited, $millions except earnings (loss) per share and shares outstanding)	Three months ended	Year ended	Three months ended			
	Mar 31, 2011	Dec 31, 2010	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010
Earnings (loss) per share	**$ 0.06**	**$0.77**	**$ (0.13)**	**$ 0.73**	**$ (0.37)**	**$ 0.55**
Net income (loss) attributable to shareholders	3	17	(3)	16	(8)	12
Preferred share dividends	(1)	-	-	-	-	-
Earnings (loss) attributable to common shareholders	2	17	(3)	16	(8)	12
Adjustments	9	14	8	(2)	9	(1)
Normalized earnings attributable to common shareholders[1]	11	31	5	14	1	11
Weighted average number of common shares outstanding (millions)	32.32	22.19	23.47	21.77	21.75	21.75
Normalized earnings per share[1]	**$0.33**	**$1.40**	**$ 0.21**	**$ 0.64**	**$ 0.05**	**$ 0.51**

(1) Normalized earnings attributable to common shareholders and normalized earnings per share are non-IFRS measures. See Non-IFRS Financial Measures.

Normalized earnings attributable to common shareholders for the first quarter of 2011 were lower than management's expectations and lower in comparison to the first quarter of 2010. The quarter-over-quarter decrease was primarily due to lower EBITDA, excluding unrealized fair value changes, from the Alberta commercial plants and portfolio optimization, and from other portfolio activities.

The Company uses normalized earnings attributable to common shareholders and normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings attributable to common shareholders are based on earnings used in the calculation of earnings per share as reported in the consolidated financial statements, adjusted for items that are not reflective of performance in the period such as fair value changes, impairments, unusual tax adjustments and gains or losses on disposal of assets and on unusual contracts. Normalized earnings per share for the first quarter of 2011 reflect normalized earnings attributable to common shareholders divided by 32.32 million weighted average common shares outstanding. See Non-IFRS Financial Measures.

Consolidated Net Income

(unaudited, $millions)	
Net income for the three months ended March 31, 2010	**$ 92**
Lower financing expenses	10
Higher Ontario and British Columbia contracted plants EBITDA	8
Unrealized changes in the fair value of CPILP's derivative instruments	4
Unrealized changes in the fair value of CPLP's energy derivative instruments and natural gas inventory held for trading	(43)
Gains on acquisitions and disposals	(28)
Lower Alberta commercial plants and portfolio EBITDA	(15)
Lower other portfolio activities EBITDA	(6)
Lower corporate EBITDA	(6)
Other	(2)
Decrease in net income	(78)
Net income for the three months ended March 31, 2011	**$ 14**

Net income decreased $78 million for the three months ended March 31, 2011 compared with the corresponding period in 2010 due to the net impact of the following:

- Financing expenses were $10 million lower for the three months ended March 31, 2011 compared with the corresponding period in 2010 due to unrealized changes in the fair value of forward bond sale contracts, including the reversal of unrealized losses related to 2010, in the first quarter of 2011. The Company did not have any similar contracts in the corresponding period in 2010.
- Ontario and British Columbia contracted plants EBITDA was higher primarily due to contributions from Island Generation following the Company's acquisition of the facility in the fourth quarter of 2010.
- The unrealized changes in the fair value of CPILP's derivative instruments primarily reflected decreases in the fair value of natural gas supply contracts in the first quarter of 2010. Alberta forward natural gas prices reflected little change in the three months ended March 31, 2011 compared to a decrease of $0.87 per GJ in the corresponding period in 2010.
- The unrealized changes in the fair value of CPLP's derivative instruments and natural gas storage held for trading that were not designated as hedges for accounting purposes, reflected unrealized losses in the first quarter of 2011 compared with unrealized gains in the corresponding period in 2010. These changes were primarily due to the impact of increases in the Alberta forward power prices on portfolio positions for these instruments in the first three months of 2011 compared with the impact of decreases in Alberta forward power prices in the corresponding period in 2010.
- On January 15, 2010, the Company sold its remaining 15% interest in the Battle River Power Syndicate Agreement (PSA) for cash proceeds of $64 million resulting in a pre-tax gain of $28 million and $2 million of associated income taxes. There was no comparable sale of assets in the first quarter of 2011.
- Alberta commercial plants and portfolio optimization EBITDA was lower primarily due to significant increases in Alberta power prices in the first quarter of 2011 which had an unfavourable impact on the Company's Alberta portfolio. This unfavourable impact was mitigated by higher generation from the dispatch of the Clover Bar Energy Centre and Joffre facility. In the first quarter of 2010, Alberta power prices were lower and had a favourable impact on the portfolio.
- The EBITDA for other portfolio activities was lower primarily due to a net loss from natural gas trading in the first three months of 2011 compared with a net gain in the corresponding period in 2010.
- Corporate general and administrative expenses were higher in the first quarter of 2011 primarily due to higher professional fees for the New England plant acquisitions and a $2 million unrealized decrease in the fair value of foreign exchange contracts. These contracts were entered into in the first quarter of 2011 in anticipation of future U.S. cash payments related to the acquisitions of the three New England power plants. See Significant and Subsequent Events.

Outlook

The following discussion should be read in conjunction with the Forward-looking Information section of this MD&A as this information contains forward-looking statements based on risks and assumptions as of the date of this MD&A and as disclosed in that section. These forward-looking statements are for the purpose of providing information about management's current expectations and plans relating to the future and may not be appropriate for other purposes.

The following table provides the Company's performance measure targets for 2011 updated for IFRS. The target for capital expenditures for plant maintenance and the Genesee mine was increased for major maintenance expenditures that would have been expensed under previous CGAAP. This measure excludes plant maintenance capital expenditures for CPILP plants, Genesee mine capital expenditures that are funded by the Company's partner for mine operations, and capital expenditures for the three New England plants discussed under Significant and Subsequent Events. None of the other targets were impacted by the transition to IFRS.

Performance Measures	2011 Targets
Allocated Capital	
Committed capital for acquisitions/developments that are in-line with targeted rates of return	$1.5 billion or higher
Operational	
Plant availability average	94% or greater
Capital expenditures for plant maintenance and Genesee mine extension	Approximately $56 million
Construction / Development	
Capital Power's final costs in the construction of Keephills 3 plant	$955 million or less with commercial operation date in the second quarter of 2011
Quality Wind and Port Dover & Nanticoke wind projects	Continue on time and on budget with commercial operation dates in 2012
Investment Performance	
Total shareholder return	Deliver total shareholder return that exceeds the median of the Company's peer group

In January 2011, Unit 3 of the Clover Bar Energy Centre experienced an unplanned outage due to blade damage in its high pressure compressor. The unit was taken out of service and returned to the manufacturer for disassembly, analysis and repair. Although the unit is under warranty, it is not possible to determine whether the repair costs are covered until the root cause of the damage is determined. Capital Power provided the Alberta Electric System Operator (AESO) with an estimated return to service date of June 30, 2011. Capital Power's repair costs, if not covered under warranty, would be subject to a $1 million deductible.

If the unit is offline for six months in 2011, and Capital Power's other operations perform as expected, the Company will not meet its 2011 plant availability target as the results for this measure would decrease to approximately 91%. Capital Power continues to have 143 MW of peaking capacity available from Clover Bar Energy Centre Units 1 and 2. An outage at Unit 2 for an engine upgrade has been tentatively scheduled for July 15, 2011 to September 1, 2011 to coincide with the timing of Unit 3's return to service.

The commissioning of Keephills 3 has been delayed due to the additional time required to clean the boiler. This stage of the commissioning process has recently been completed and the Company expects the commercial operation date of Keephills 3 will be during the third quarter of 2011, later than previous expectations of the second quarter. The delay is expected to add approximately $20 million to $30 million or 2% to 3% in capital costs for the Company's share of the project. The delay is also expected to have a slightly positive impact on 2011 net income and a slightly negative impact on cash from operating activities.

In the first quarter of 2011, Alberta power spot prices averaged $82/MWh compared to an average of $46/MWh for the fourth quarter of 2010. The increase was the result of colder than normal weather and changes in the supply of electricity due to the shutdown of two large coal plants and derates at other generation units. Based on the Company's Alberta portfolio position in the first quarter of 2011, coupled with the unforeseen outage of Clover Bar Energy Unit 3, this spike in power prices had an unfavourable impact on the Company's net income and funds from operations in the period.

If Alberta power prices for the balance of 2011 settle on average in the range of low-$60/MWh, the Company expects full year normalized earnings per share for 2011 to be approximately $1.40. This estimate reflects the following updates from previous guidance included in the Company's 2010 annual MD&A:

- The previous guidance for 2011 normalized earnings per share was based on an average Alberta power price of $50/MWh for 2011 whereas the Company's current expectation is an average of low-$60/MWh. Although the increase in Alberta power prices had an unfavourable impact on the Company's Alberta portfolio position in the first quarter, subsequent changes to the unhedged portion of the portfolio and generation from Keephills 3 commencing by the end of the third quarter of the year, are expected to result in full year earnings that exceed previous guidance and internal plans, as long as current forward prices for Alberta power for the remainder of the year are realized. At March 31, 2011, the Alberta portfolio positions were as follows for the remainder of 2011 and for 2012 and 2013:

Alberta Power Price Sensitivity	April to December 2011	Full year 2012	Full year 2013
% Sold forward	64%	35%	17%
Contracted price	Low-$60/MWh	Mid-$60/MWh	Mid-$60/MWh

- The impacts of transitioning to IFRS from previous CGAAP are expected to be as follows:
    - The Company still expects the maintenance cost for the Genesee 1 scheduled outage of March 28, 2011 to April 18, 2011 to be approximately $13 million. However, approximately $11 million of these costs are expected to be capitalized under IFRS rather than expensed, and depreciated over the next two years.
    - Similarly, $5 million of the Company's share of maintenance costs for the Joffre plant in 2011 are expected to be capitalized and depreciated under IFRS rather than expensed.
    - Depreciation expense for 2011 is expected to include approximately $20 million for the depreciation on current and prior years' shutdown maintenance costs that are capitalized under IFRS. Under previous CGAAP, the costs were expensed as incurred.
- The estimated useful lives of the Company's Genesee and Keephills 3 plants were extended from 35 years to 45 years, as discussed under Critical Accounting Estimates and Policies. The impact on depreciation expense in 2011 is expected to be a decrease of approximately $14 million from previous estimates.
- The Company's three New England plant acquisitions are expected to contribute $34 million to $38 million in income after depreciation expense and before financing and income tax expenses in 2011. This estimate is based on the assumptions discussed under Subsequent Events.
- Financing costs in 2011 will include interest on the $300 million medium-term notes issued in April 2011 as discussed under Subsequent Events.
- In March 2011, the Company issued 9.3 million common shares to the public thereby diluting the Company's earnings per share. In accordance with the terms of the CPLP partnership agreement, net income from CPLP for the year will be allocated to the partners (subsidiaries of EPCOR and Capital Power) on the same basis as distributions for the year are allocated. Since the public share offering closed before the date of record for the first quarter distribution by CPLP, the transaction effectively occurred January 1, 2011 for purposes of allocating net income to the partners. As a result, Capital Power's and EPCOR's share of net income for the year will be approximately 46% and 54%, respectively assuming that there are no changes to the current common share ownerships for the balance of the year.

The 2011 targets and normalized earnings per share forecasts are based on numerous assumptions including power and natural gas price forecasts, as described in the Forward-looking Information section. However, they do not include assumptions regarding changes to the current ownership or business of CPILP resulting from the strategic alternatives review, impacts from potential future acquisitions or development activities, or potential impacts from unplanned plant outages including outages at facilities of other market participants and the related impacts on market power prices.

CPILP's process to review strategic alternatives is ongoing and CPILP anticipates providing an update later in the second quarter of 2011. In March 2011, CPILP executed an interim Power Purchase Arrangement (PPA) with Progress Energy Inc. for the partnership's two North Carolina facilities that will be in effect to the earlier of replacement with long-term PPAs, and July 31, 2011. The terms of the interim PPA, effective April 1, 2011, follow the guidelines set forth in the January 26, 2011 Order on Arbitration issued by the North Carolina Utilities Commission, but are not binding on the terms of the expected long-term PPAs.

The New England plant acquisitions discussed under Significant and Subsequent Events contribute approximately US$670 million towards the Company's target of $1.5 billion of capital to be committed in 2011. These acquisitions will be financed by proceeds from the $232 million common share offering in March 2011 and the use of the Company's existing credit facilities. See Significant and Subsequent Events.

The Company's estimated capital expenditures in 2011 in the following table exclude the cost of acquisitions and potential new development projects. However, the table does include the estimated plant maintenance capital expenditures in 2011 for the New England plants following the acquisitions in the second quarter. See Significant and Subsequent Events.

(unaudited, $millions) **Capital Expenditures**			Year ended Dec 31, 2011 Estimated[(1)]
CPLP	Sustaining	Plant maintenance	40
		Genesee mine maintenance[(2)]	16
		New England plant maintenance	7
		Information technology	13
		Other	14
			90
CPLP	Growth	Keephills 3	88
		Quality Wind	148
		Port Dover & Nanticoke	54
			290
CPLP Total			380
CPILP	Sustaining	Plant maintenance	25
	Growth		5
CPILP Total			30
			410

(1) Capital expenditures for the year ended December 31, 2011 are based on management's estimates.

(2) Capital expenditures for Genesee mine maintenance represent only those capital additions funded by the Company for the Genesee mine operation.

The capital expenditure estimates in the above table reflect the following updates to the guidance included in the 2010 annual MD&A:

- Estimated plant maintenance capital expenditures are approximately $16 million higher due to the impact of IFRS whereby costs for major maintenance are capitalized rather than expensed.
- Approximately $7 million of plant maintenance capital expenditures are anticipated for the three New England plants.
- Estimated capital expenditures for Keephills 3 are approximately $20 million to $30 million higher due to delays for additional cleaning of the boiler.
- Construction of the Port Dover & Nanticoke wind project was delayed for completion of the land title transfers resulting in $44 million of planned expenditures being deferred to 2012. The delay is not anticipated to impact the completion date of the fourth quarter of 2012 or total project cost of $340 million.

The 2011 estimated capital expenditures for information technology are primarily for a new energy trading and risk management system. Included in the other capital expenditure estimate in the above table are leasehold improvements for the Company's Edmonton and Calgary offices as their leases expire in 2011.

Significant Events

$232 million common share offering

In March 2011, the Company issued and sold 9,315,000 common shares at a price of $24.90 per share to a syndicate of underwriters co-led by TD Securities Inc. and CIBC World Markets Inc., for gross proceeds of $232 million less issue costs of $9 million. The sale included an initial sale of 8,100,000 common shares on March 17, 2011 followed by the sale of an additional 1,215,000 common shares on March 28, 2011 pursuant to the exercise of an over-allotment option granted to the syndicate of underwriters. The net proceeds from the common share offering were used to repay a portion of the outstanding indebtedness under the Company's credit facilities. The Company expects to draw down on its credit facilities to finance the acquisitions of three New England plants discussed below.

Acquisition of two New England power plants

In February 2011, CPLP entered into an agreement to acquire two generating facilities from Brick Power Holdings LLC, one facility located in Tiverton, Rhode Island (Tiverton) and one facility located in Rumford, Maine (Rumford). Both plants are natural gas-fired combined cycle power generation facilities serving the New England region in the U.S. Northeast, and have a maximum combined capacity of 549 MW. The Company expects the transaction to close on April 29, 2011 at a purchase price of US$315 million subject to working capital adjustments and other closing adjustments.

Both plants are merchant facilities and sell their output into the New England Power Pool (NEPOOL). The plants began commercial operations in 2000 and have similar design configurations that utilize a single fuel GE 7FA power island. The Company commissioned and operates similar technology at the Frederickson power facility in Washington State.

Tiverton and Rumford supply electricity to the New England Independent System Operator (ISO-NE). Both plants are exempt wholesale generators and have Federal Energy Regulatory Commission (FERC) authorization to sell capacity, energy, and ancillary services at market-based rates. The plants are operated as mid-merit generation units and sell their outputs on an hourly basis into the NEPOOL. The NEPOOL serves six New England states: Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont which contain approximately 14 million people and over 6 million households and businesses. The NEPOOL is subject to FERC jurisdiction and has more than 400 participants, over 8,000 miles of transmission lines, and 13 interconnections to the New York and Canadian power systems. It is one of the most advanced and liquid markets in the U.S. and has a peak demand of approximately 28,000 MW.

Subsequent Events

$300 million debt offering

On April 18, 2011, CPLP completed a public offering of $300 million unsecured medium-term notes. The notes have a coupon rate of 4.6%, payable semiannually commencing on June 1, 2011, and mature on December 1, 2015. The net proceeds of the offering will be used for general corporate purposes including repayment of amounts owing under credit facilities, short-term investment, financing of ongoing capital projects and working capital requirements. The notes have been rated BBB by Standard & Poor's and BBB by DBRS Limited. The offering was made pursuant to CPLP's short form base shelf prospectus dated April 14, 2010 and a related pricing supplement dated April 13, 2011.

Acquisition of a third New England power plant

In March 2011, the Company entered into an agreement to acquire Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport Energy), from affiliates of LS Power Equity Advisors, LLC. Bridgeport Energy is a natural gas-fired combined cycle power generation plant located in Bridgeport, Connecticut, with a nominal capacity of 520 MW. It is an efficient, young, mid-merit generation plant that can maximize energy and ancillary services revenue through operational flexibility.

Under the purchase and sale agreement, CPLP is acquiring one hundred per cent of the equity interests in Bridgeport Energy, LLC. The transaction closed on April 28, 2011 at a purchase price of US$355 million plus working capital adjustments and other closing adjustments.

As part of the NEPOOL, Bridgeport Energy dispatches into the premium Southwest Connecticut Zone of the ISO-NE market, and has historically received payments for energy, capacity and ancillary services. Bridgeport Energy is a modern, efficient plant that has among the lowest heat rates in ISO-NE. The site has adequate space to develop a peaking facility when market conditions warrant.

Bridgeport Energy entered commercial operation in July 1999. It is equipped with two Siemens V84.3A gas turbines, which are the same design as those used at CPILP's facility in Colorado, and produces additional output from two Heat Recovery Steam Generators and one single-reheat condensing steam turbine. Electrical interconnection into the United Illuminating system is made via the Singer 345kV substation, and natural gas is supplied through a lateral to the Iroquois Gas pipeline system. The facility was designed to minimize environmental impacts and utilizes advanced emission control technologies, including selective catalytic reduction nitrogen oxide controls.

The Company expects to permanently finance both New England acquisitions using a combination of debt and equity. It also expects the acquisitions to contribute approximately $51 million - $55 million to EBITDA and to increase depreciation expense by approximately $17 million in 2011. Their contribution to earnings in 2012 is expected to be similar to the 2011 forecast on an annualized basis and adjusted for the seasonal impacts of higher production and pricing for cooling in the summer months. In future years, earnings from the facilities are expected to increase significantly following the expected recovery of power prices in the New England market as the U.S. economy strengthens. The 2011 and 2012 earnings expectations are based on the following assumptions: an exchange rate of $1.00 to US$1.00 and plant output based on an hourly dispatch model which uses projected hourly power and natural gas prices in the ISO-NE market to determine when it is economically feasible to dispatch.

Following the acquisitions, Capital Power will have added or placed into development approximately 2,000 MW of generating capacity since the Company's July 2009 IPO. The acquisitions demonstrate the Company's commitment to its growth strategy aimed at reaching 10,000 MW of assets by 2020. The acquisitions also provide Capital Power with the foundation for a networked hub of assets in the U.S. Northeast, which is one of the Company's target markets, and contributes to a balanced portfolio of contracted and merchant assets. As relatively young, highly efficient natural gas-fired plants that use proven technologies, these additions to the fleet fit the Company's technology and operating focus.

Results by Plant Category

The Company reports results of operations in the following categories: (i) Alberta commercial plants and portfolio optimization, (ii) Alberta contracted plants, (iii) Ontario and British Columbia contracted plants, (iv) CPILP plants, (v) Other portfolio activities, and (vi) Corporate.

Generation volume

(unaudited, GWh)	Three months ended	
Electricity generation[1]		
	March 31, 2011	March 31, 2010
Alberta commercial plants		
Genesee 3	482	483
Joffre	98	41
Clover Bar Energy Centre 1, 2 and 3	162	43
Taylor Coulee Chute	-	-
Clover Bar Landfill Gas	8	10
Weather Dancer	-	-
	750	577
Alberta contracted plants		
Genesee 1	768	813
Genesee 2	831	825
	1,599	1,638
Ontario and British Columbia contracted plants		
Kingsbridge 1	31	26
Miller Creek	5	7
Brown Lake	14	13
Island Generation	52	-
	102	46
Total excluding CPILP plants	**2,451**	**2,261**
CPILP plants	1,139	1,268
Total plants	**3,590**	**3,529**
Sundance PPA	**758**	**751**

(1) Electricity generation reflects the Company's share of plant output.

Plant availability

(unaudited)	Three months ended	
Generation plant availability[1]	March 31, 2011	March 31, 2010
Alberta commercial plants		
Genesee 3	100%	100%
Joffre	99%	100%
Clover Bar Energy Centre 1, 2 and 3	65%	72%
Taylor Coulee Chute	100%	98%
Clover Bar Landfill Gas	95%	96%
Weather Dancer	-	83%
	87%	90%
Alberta contracted plants		
Genesee 1	92%	99%
Genesee 2	100%	99%
	96%	99%
Ontario and British Columbia contracted plants		
Kingsbridge 1	98%	99%
Miller Creek	78%	37%
Brown Lake	100%	97%
Island Generation	99%	-
	97%	74%
Average excluding CPILP plants[2]	**93%**	**93%**
CPILP plants	92%	95%
Average all plants[2]	**92%**	**94%**
Sundance PPA	**98%**	**97%**

(1) Plant availability represents the percentage of time in the period that the plant was available to generate power regardless of whether it was running, and therefore is reduced by planned and unplanned outages.

(2) Average generation plant availability is an average of individual plant availability weighted by the capacity owned or operated by the Company.

The increase in total plant electricity generation, excluding generation from the Sundance PPA, for the three months ended March 31, 2011 compared with the corresponding period in 2010 primarily relates to Joffre, Clover Bar Energy Centre, and Island Generation following its acquisition in the fourth quarter of 2010, partly offset by lower generation from the CPILP plants.

Joffre and Clover Bar Energy Centre are mid-merit and peaking plants, respectively, which operate when it is economical to do so. As a result of higher Alberta power prices and higher price volatility, both plants were dispatched more in the first quarter of 2011. Availability of Clover Bar Energy Centre, however, was negatively impacted by outages in both 2010 and 2011. Unit 3 was taken offline on January 15, 2011 due to blade damage in its high pressure compressor. The unit is not expected to be back online until June 30, 2011. In the first quarter of 2010 Units 2 and 3 were taken offline for 18 and 21 days, respectively for a high pressure oil system inspection. A mechanical failure in the main turbine section of Unit 2, unrelated to the oil system inspection, was subsequently identified and the repair work was initiated in March in 2010. The unit was offline for a total of 43 days during the first quarter and returned to service on September 22, 2010.

Miller Creek was offline for 25 days during the first quarter of 2011 for repairs compared with 77 days for scheduled maintenance in the corresponding period of 2010.

Financial results

(unaudited, $millions)	Three months ended	
	March 31, 2011	March 31, 2010
Revenues and other income		
Alberta commercial plants and portfolio optimization	$ 266	$ 235
Alberta contracted plants	77	73
Ontario and British Columbia contracted plants	13	3
CPILP plants	128	139
Other portfolio activities	34	43
Corporate	6	6
Inter-plant category transaction eliminations	(20)	(15)
	504	484
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	(49)	12
Unrealized changes in fair value of CPILP's foreign exchange contracts	3	5
	(46)	17
	$ 458	**$ 501**
Gross income		
Alberta commercial plants and portfolio optimization	$ 50	$ 65
Alberta contracted plants	62	58
Ontario and British Columbia contracted plants	13	3
CPILP plants	72	77
Other portfolio activities	9	15
Corporate	6	6
Inter-plant category transaction eliminations	(13)	(14)
	199	210
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	(34)	9
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	2	(2)
	(32)	7
	$ 167	**$217**
EBITDA[(1)]		
Alberta commercial plants and portfolio optimization	$ 38	$ 53
Alberta contracted plants	47	44
Ontario and British Columbia contracted plants	10	2
CPILP plants	45	49
Other portfolio activities	-	6
Corporate	(26)	(20)
Inter-plant category transaction eliminations	-	-
	114	134
Unrealized changes in fair value of CPLP's power and natural gas derivative instruments and natural gas held for trading	(34)	9
Unrealized changes in fair value of CPILP's foreign exchange and natural gas contracts	2	(2)
	(32)	7
Gain on sale of power syndicate agreement	-	28
	$ 82	**$ 169**

(1) The results by plant category, except for EBITDA, have been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

Spot price averages	Three months ended March 31, 2011	March 31, 2010
Alberta power ($/MWh)	82	41
Eastern region power ($/MWh)	32	34
Western region power (Mid-C) ($/MWh)	22	43
Alberta natural gas (AECO) ($/Gj)[(1)]	4	5

Capital Power's Alberta portfolio's realized power price ($/MWh)[(2)]	64	67

[(1)] Gigajoule (Gj). AECO means a historical virtual trading hub located in Alberta and known as the Nova Inventory Transfer System operated by TransCanada Pipelines Limited.

[(2)] The price realized on the Company's commercial contracted sales and portfolio optimization activities.

Alberta commercial plants and portfolio optimization

The gross income and EBITDA for the Alberta commercial plants and portfolio optimization were lower in the first quarter of 2011 compared with the corresponding period in 2010 primarily due to lower margins realized on the merchant trading portfolio and higher availability incentive payments for the Sundance PPA, partly offset by higher contributions from Joffre and the Clover Bar Energy Centre units. Higher Alberta spot prices and higher volatility in those prices in the first quarter of 2011 provided more opportunities to dispatch the plants. The average Alberta power spot price was $82/MWh for the first quarter of 2011 and $41/MWh for the corresponding period in 2010. The increase was the result of cooler weather than normal and changes in supply due to the shutdown of two large coal plants and derates of other units in the region.

The impact of the sudden increase in Alberta power prices on the commodity optimization portfolio resulted in lower margins in the first quarter of 2011. In the corresponding period in 2010, lower Alberta power prices had a favourable impact, resulting in higher margins. The Company's average realized price for the Alberta commercial portfolio decreased from approximately $67/MWh in the first quarter of 2010 to approximately $64/MWh in the corresponding period in 2011 as the Company's Alberta portfolio was sold forward under merchant and wholesale financial contracts at lower prices.

The Sundance PPA incentive payments were higher due to higher rolling average power prices. The price for availability incentive income and penalties is a function of a 30-day rolling average of Alberta power prices.

Clover Bar Energy Centre Unit 3 was taken offline on January 15, 2011 onwards due to blade damage in the high pressure compressor, and returned to the manufacturer. In 2010, Unit 2 went offline on March 8 due to a mechanical failure in the main turbine section. The repair work for Unit 2 was covered under warranty by the manufacturer but it has yet to be determined whether the repair work on Unit 3 will be covered. Accordingly, the repairs did not have a material impact on operating and maintenance expenses in either period. Unit 3 is expected to be back online on June 30, 2011.

The increase in revenues primarily reflected the impact of higher Alberta power prices on the generation volume from the plants and higher pricing for the supply of electricity to EPCOR's rate-regulated tariff (RRT) customers, partly offset by losses on merchant financial sell contracts in the first quarter of 2011 compared with gains on these contracts in the first quarter of 2010. The increase in revenue from the Company's RRT business in the first quarter of 2011 did not have a significant impact on EBITDA as the Company's purchases and revenues for this business are equally impacted by changes in the Alberta power price and provide a low margin per MWh.

Alberta contracted plants

Revenues, gross income and EBITDA for the Alberta contracted plants increased in the three months ended March 31, 2011, compared with the corresponding period in 2010 primarily due to higher availability incentive revenues as a result of higher rolling average power prices which were based on Alberta power spot prices. Higher Alberta power prices in the first quarter of 2011 also led to increased excess energy revenues.

Ontario and British Columbia contracted plants

The higher revenues, gross income and EBITDA for the Ontario and British Columbia contracted plants primarily reflect the contribution from the Island Generation facility following its acquisition in the fourth quarter of 2010.

CPILP plants

CPILP plants' gross income and EBITDA were lower in the three months ended March 31, 2011 compared with the corresponding period in 2010 primarily due to lower margins at the Ontario facilities as a result of an outage at the Tunis plant and higher wood waste costs for the Calstock facility, lower generation at the hydroelectric plants as a result of lower water flows, and lower margins at the Northwest U.S. plants. Revenues for the three months ended March 31, 2011 decreased $11 million primarily due to lower fuel recoveries at the California, Kenilworth and Morris plants which were driven by reduced generation and lower natural gas supply prices. This decrease in revenues was partly offset by decreased fuel expenses.

Other portfolio activities

Other portfolio activities include environmental credits and natural gas trading in North American markets and electricity trading in the eastern Canada, U.S. Northeast and U.S. Pacific Northwest markets. The decrease in revenue, gross income and EBITDA for other portfolio activities was primarily due to net losses from natural gas trading activities in the first quarter of 2011 compared with net gains in the corresponding period in 2010. The decrease in natural gas trading revenues was partly offset by higher revenues for emission credit sales. The emission credit sales contributed only a small quarter over quarter increase in gross income and EBITDA due to the higher cost of credits sold in the first quarter of 2011 compared with the corresponding period in 2010.

Corporate

Corporate includes revenues for cost recoveries, the cost of support services such as treasury, finance, internal audit, legal, human resources, corporate risk management, asset management and health and safety, as well as business development expenses. The cost recovery revenues are primarily intercompany revenues which are offset by interplant category transactions in the consolidated results. The lower EBITDA in the first quarter of 2011 compared with the corresponding period in 2010 was primarily due to professional fees for the New England plant acquisitions and a $2 million unrealized decrease in the fair value of foreign exchange contracts. The foreign exchange contracts were entered into in the first quarter of 2011 in anticipation of future U.S. cash payments for the acquisitions of the three New England power plants. See Significant and Subsequent Events.

Unrealized changes in fair value of derivative instruments and natural gas inventory held for trading

Changes in the fair value of CPLP's derivative electricity and natural gas contracts and natural gas storage held for trading, that were not designated as hedges for accounting purposes, decreased the gross income by $34 million in 2011. These changes primarily reflected the impact of increases in Alberta forward power prices on portfolio positions. In the first quarter of 2010, the fair value changes of these instruments increased gross income by $9 million, reflecting the impact of decreases in Alberta forward power prices on portfolio positions.

CPILP's revenues included net gains of $3 million for changes in the fair value of foreign exchange contracts in the first quarter of 2011 compared with net gains of $5 million in the first quarter of 2010. The increases in the fair value of these contracts were primarily due to a decrease in the forward prices for U.S. dollars relative to Canadian dollars of $0.023 in the first quarter of 2011 and $0.024 in the first quarter of 2010. The net gain was smaller in the first quarter of 2011 due to a decrease in the amount of U.S. dollar forward foreign exchange contracts held.

The unrealized changes in the fair value of CPILP's natural gas supply contracts that were not designated as hedges for accounting purposes were included in fuel expense. These changes were immaterial in the first quarter of 2011 reflecting little change in Alberta forward prices for natural gas, and were a $7 million loss in the corresponding period in 2010 due to a decrease of $0.87/Gj in those prices.

Gain on sale of power syndicate agreement

On January 15, 2010, the Company sold its remaining 15% interest in the Battle River Power Syndicate Agreement (PSA) for cash proceeds of $64 million resulting in a pre-tax gain of $28 million and $2 million of associated income taxes. There was no comparable gain on sale of assets during the first quarter of 2011. The sale of the Battle River PSA did not have an impact on earnings attributable to the common shareholders of the Company as approximately $11 million was added to the carrying amount of the asset when it was acquired from EPCOR representing the Company's 27.8% interest in the asset's fair value increment. Accordingly this increment was attributable to the equity holders of the Company and not the non-controlling interests.

Consolidated Other Expenses

Finance expense

Finance expenses were $10 million lower for the three months ended March 31, 2011, compared with the corresponding period in 2010. Unrealized changes in the fair value of forward bond sale contracts including the reversal of unrealized losses relating to 2010 resulted in a net unrealized gain of $10 million in the first quarter of 2011. At the end of the first quarter of 2011, the Company had three $100 million forward bond sale contracts outstanding with an unrealized fair value of $4 million included in derivative instrument assets on the statement of financial position. There were no similar contracts in the corresponding period of 2010.

Depreciation and amortization

Depreciation and amortization expense was higher for the three months ended March 31, 2011 compared with the corresponding period in 2010, primarily due to the depreciation of Island Generation following its acquisition in the fourth quarter of 2010. This was partly offset by lower depreciation on the Genesee assets as a result of the change in the estimated useful life of the coal plants from 35 years to 45 years. See Critical Accounting Estimates and Policies.

Income tax expense

In the first quarter of both 2010 and 2011, income taxes on income for the respective periods were substantially offset by the impact of changes in income tax laws and rates on future income tax assets and liabilities.

Non-controlling interests

The non-controlling interests in CPILP reflect approximately 70.6% of CPILP net income which was lower for the three months ended March 31, 2011 than for the corresponding period in 2010. The non-controlling interests in CPLP reflected approximately 54.1% (72.2% for the first quarter of 2010) of the net income from CPLP (net of preferred share dividends), which was lower in the three months ended March 31, 2011 than the corresponding period in 2010. Non-controlling interests for the three months ended March 31, 2010 also included 100% of the gain on sale of the Battle River PPA. The sale had no impact on the Company's net income as its 27.8% share of the fair value of the Battle River PPA was recognized in the purchase price allocation for its acquisition of power generation assets and operations (the Reorganization) from EPCOR Utilities Inc. on July 9, 2009.

Income from CPLP included approximately 29.4% (30.3% in the first quarter of 2010) of the CPILP net income. Therefore the non-controlling interests in CPLP included approximately 15.9% (54.1% of 29.4%) of CPILP net income in the first quarter of 2011 and 21.9% (72.2% of 30.3%) in the first quarter of 2010.

Non-IFRS Financial Measures

The Company uses (i) EBITDA, (ii) funds from operations, (iii) funds from operations excluding non-controlling interests in CPILP, (iv) normalized earnings attributable to common shareholders and (v) normalized earnings per share as financial performance measures. These terms are not defined financial measures according to IFRS and do not have standardized meanings prescribed by IFRS, and therefore may not be comparable to similar measures used by other enterprises. These measures should not be considered alternatives to net income, cash flow from operating activities or other measures of financial performance calculated in accordance with IFRS. Rather, these measures are provided to complement IFRS measures in the analysis of the Company's results of operations from management's perspective.

EBITDA

Capital Power uses EBITDA to measure the operating performance of plants and groups of plants from period to period. A reconciliation of EBITDA to net income is as follows:

(unaudited, $millions)	Three months ended				
	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010
Revenues	$ 440	$ 429	$ 493	$ 301	$ 484
Other income	18	8	18	12	17
Energy purchases and fuel	291	232	278	196	284
Gross income	**167**	**205**	**233**	**117**	**217**
Other raw materials and operating charges	29	43	20	22	19
Staff costs and employee benefits expense	39	43	44	47	41
Other administrative expenses	10	19	17	11	10
Property taxes	5	4	5	4	5
Impairment charges	-	1	66	(2)	-
Foreign exchange losses (gains)	2	1	1	(2)	1
Gains on acquisitions and disposals	-	(2)	-	-	(28)
EBITDA	82	96	80	37	169
Depreciation and amortization	58	66	56	62	57
Finance expense	9	13	26	20	19
Income taxes expense (recovery)	1	(5)	1	(11)	1
Net income	**14**	**22**	**(3)**	**(34)**	**92**
Attributable to:					
Non-controlling interests	11	25	(19)	(26)	80
Shareholders of the Company	3	(3)	16	(8)	12

Funds from operations and funds from operations excluding non-controlling interests in CPILP

Capital Power uses funds from operations to measure the Company's ability to generate funds from current operations. Funds from operations are cash provided by operating activities, including financing and current income tax expenses, and excluding changes in working capital. Changes in working capital are impacted by the timing of cash receipts and payments and are not comparable from period to period. As a result of the transition to IFRS, interest paid, excluding capitalized interest, and income taxes paid and recovered have been moved into the body of the consolidated statement of cash flows as part of operating activities. These amounts were previously disclosed as supplementary information and captured within the consolidated statement of cash flows within changes in non-cash operating working capital. In its funds from operations and funds from operations excluding non-controlling interests in CPILP, the Company includes interest and current income tax expense recorded during the period, rather than interest and taxes paid as these differences are impacted by the timing of cash receipts and payments and are not comparable from period to period. Therefore, the Company uses funds from operations as its primary operating cash flow measure. The Company measures its interest in cash flows by excluding the non-controlling interest in CPILP's cash flows. A reconciliation of (i) funds from operations and (ii) funds from operations excluding non-controlling interests in CPILP, to cash provided by operating activities is as follows:

(unaudited, $millions)	Three months ended	
	Mar 31, 2011	Mar 31, 2010
Funds from operations excluding non-controlling interests in CPILP	**$ 78**	**$ 71**
Funds from operations due to non-controlling interests in CPILP	21	28
Funds from operations	**99**	**99**
Adjustments:		
Unrealized changes in the fair value of forward bond contracts	10	-
Finance expense	9	19
Interest paid	(12)	(12)
Income taxes (paid) / recovered	(9)	8
Current income tax expense excluding future income taxes	4	14
Change in non-cash operating working capital	-	(1)
Cash provided by operating activities	**101**	**127**

Normalized earnings and normalized earnings per share

The Company uses normalized earnings per share to measure performance by period on a comparable basis. Normalized earnings per share is based on earnings used in the calculation of earnings per share according to

IFRS adjusted for items that are not reflective of performance in the period such as fair value changes, impairments, unusual tax adjustments and gains or losses on disposal of assets or on unusual contracts such as the contract for maintenance of EPCOR's Rossdale plant. A reconciliation of net income (loss) attributable to shareholders to normalized earnings attributable to common shareholders, and earnings (loss) per share to normalized earnings per share is as follows:

(unaudited, $millions except earnings (loss) per share)	Three months ended	Year ended	Three months ended			
	Mar 31, 2011	Dec 31, 2010	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010
Earnings (loss) per share	**$ 0.06**	**$ 0.77**	**$ (0.13)**	**$ 0.73**	**$ (0.37)**	**0.55**
Net income (loss) attributable to shareholders	3	17	(3)	16	(8)	12
Preferred share dividends	(1)	-	-	-	-	-
Earnings (loss) attributable to common shareholders	**2**	**17**	**(3)**	**16**	**(8)**	**12**
Adjustments						
Unrealized changes in fair value of CPLP's derivative instruments and natural gas held for trading	9	9	3	(2)	8	-
Unrealized changes in fair value of CPILP's derivative instruments	-	-	(1)	-	1	-
Obligation to EPCOR for Rossdale plant	-	2	-	2	-	-
Acquisition loss for Island Generation acquisition	-	6	6	-	-	-
Change in prior quarters' adjustments, for change in non-controlling percentage interest	-	1	1	-	-	-
Impact of asset impairments recognized by subsidiaries	-	(5)	-	(5)	-	-
Income tax adjustments	-	1	(1)	3	-	(1)
	9	14	8	(2)	9	(1)
Normalized earnings attributable to common shareholders	**11**	**31**	**5**	**14**	**1**	**11**
Normalized earnings per share	**$ 0.33**	**$ 1.40**	**$ 0.21**	**$ 0.64**	**$ 0.05**	**$ 0.51**

Financial Position

The significant changes in the Consolidated Statements of Financial Position from December 31, 2010 to March 31, 2011 were as follows:

(unaudited, $millions)	Increase (decrease)	Explanation of increase (decrease)
Trade and other receivables	(37)	Primarily due to lower customer energy consumption, lower generation sales receivable from the AESO resulting from lower power prices in March 2011 compared with December 2010, and collection of the 2010 greenhouse gas emission compliance cost recovery in the first quarter of 2011 from the Genesee 1 and 2 PPA owner.
Property, plant and equipment	28	Capital expenditures partly offset by depreciation and the impact of the strengthening Canadian dollar on the translation of property, plant and equipment of U.S. subsidiaries.
Intangible assets	(21)	Primarily due to amortization and the impact of the strengthening Canadian dollar on the translation of PPAs of U.S. subsidiaries.
Net derivative financial instruments liabilities	85	Primarily due to decreases in the fair value of derivative instrument power and natural gas contracts.
Trade and other payables	(36)	Primarily due to lower accruals for energy purchases resulting from lower customer energy consumption and lower power prices in March 2011 compared with December 2010.
Loans and borrowings (including current portion)	(188)	Primarily due to net repayments on CPLP's and CPILP's credit facilities.
Non-controlling interests	(70)	Non-controlling interests' share of CPLP and CPILP distributions and other comprehensive loss, partly offset by non-controlling interests' share of CPLP and CPILP net income.
Share capital	227	Primarily due to the issuance of common share capital in March 2011, partly offset by common share dividends and other comprehensive loss.

Liquidity and Capital Resources

Cash inflows (outflows)		
(unaudited, $millions)	Three months ended March 31, 2011	Explanation
Cash from operating activities	$ 101	See Funds from Operations
Investing	(78)	Capital expenditures, primarily for property plant and equipment related to the construction of Keephills 3, and the Quality Wind and Port Dover & Nanticoke projects.
Financing	(4)	Net debt repayments under CPLP's and CPILP's credit facilities, distributions to non-controlling interests and dividends paid to shareholders, partly offset by proceeds from common shares issuance.

In the first quarter of 2011, Capital Power Corporation completed a $232 million common share offering, as described under Significant Events. The proceeds of the offering were invested in CPLP to finance the New England plant acquisitions.

On March 31, 2011, CPLP had $1,220 million of credit facilities, of which $986 million remained available as CPLP had $74 million of long-term debt and $160 million of letters of credit outstanding under the facilities. In the first quarter of 2011, CPLP made a net repayment of $143 million on amounts drawn under its revolving credit facilities. In addition, Capital Power Corporation had an undrawn bank line of credit of $5 million.

In April 2011, CPLP issued $300 million medium-term notes as discussed under Subsequent Events. In March 2011, CPLP entered into three $100 million forward bond sale transactions which hedged a portion of the exposure to interest rate risk on the medium-term note issue. These forward bond sale contracts were settled in April 2011.

CPLP's available credit facilities will provide it with adequate funding for ongoing development projects and the $235 million of principal debt repayments in 2011.

On March 31, 2011, CPILP had credit facilities of approximately $364 million, of which $310 million remained available as CPILP had $53 million of long-term debt and $1 million of letters of credit outstanding under the facilities. In the first quarter of 2011, CPILP made a net repayment of $33 million on amounts drawn under its credit facilities. CPILP's outstanding long-term debt also reflects a decrease of $10 million in the first three months of 2011 relating to the translation of its U.S. dollar denominated debt.

CPLP has received a corporate credit rating of BBB from S&P and a long-term debt credit rating of BBB from DBRS. The BBB rating assigned by S&P is the fourth highest rating of S&P's ten corporate credit ratings. According to S&P, a BBB corporate credit rating exhibits adequate capacity to meet financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments.

The BBB rating assigned by DBRS is the fourth highest rating of DBRS' ten rating categories for long-term debt obligations. According to DBRS, long-term debt rated BBB is of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities.

Having an investment grade credit rating enhances CPLP's ability to re-finance existing debt as it matures and to access cost competitive capital for future growth.

Capital Expenditures

(unaudited, $ millions)	2011		Total project		
	Three months ended Mar 31	Full year estimate(1)	Incurred to Mar 31, 2011(2)	Total cost estimate(1)	Expected completion date
CPLP					
Keephills 3	$ 26	$ 88	$ 918	$ 980	3rd quarter 2011
Quality Wind	30	148	53	455	4th quarter 2012
Port Dover & Nanticoke	19	54	42	340	4th quarter 2012
Sustaining	9	90			
Total CPLP	84	380			
CPILP					
North Carolina plants enhancement	2	5	93	96	2011
Maintenance capital	5	25			
Total CPILP	7	30			
Total capital expenditures(3)	91	410			
Emission credits	10				
Less capitalized interest	(12)				
Payments to acquire property plant and equipment and other assets	89				

(1) Capital expenditures to be incurred over the life of the project and in the twelve months ended December 31, 2011 are based on management's estimates.

(2) Total project capital expenditures incurred to March 31, 2011 reflect capital expenditures since the inception of the project.

(3) Capital expenditures include capitalized interest. Capital expenditures excluding capitalized interest are presented on the Statement of Cash Flows as Payments to acquire property, plant and equipment and other assets.

During the commissioning process, progress on the Keephills 3 project has been delayed by the need for additional cleaning of the boiler. As a result, the Company expects the commercial operation date of Keephills 3 to move to the third quarter of 2011, later than previous expectations of the second quarter. This is expected to add approximately $20 million to $30 million or 2% to 3% in capital costs of the Company's share of the project.

The delay is also expected to have a slightly positive impact on 2011 net income and a slightly negative impact on cash from operating activities.

Construction of the Quality Wind project remains on target to the project cost forecast and schedule. Construction of the Port Dover & Nanticoke project was delayed by completion of the land title transfers which resulted in $44 million of expenditures planned for 2011 being deferred to 2012. The delay is not expected to impact the planned completion date or total cost of the project. The capital expenditures incurred on the project in the first quarter of 2011 primarily reflect a payment to the supplier of the wind turbines.

Sustaining capital expenditures include spending on plant maintenance, the Genesee mine, information technology for a new energy trading and risk management system, and leasehold improvements for offices in Calgary and Edmonton. The full year estimates have been revised for the impacts of IFRS which resulted in an increase of approximately $16 million in capital expenditures for plant maintenance costs. The full year estimates have also been updated to include $7 million of major plant maintenance for the New England plants. The maintenance capital expenditures for the Genesee 1 outage in the second quarter of 2011 are estimated to be $11 million.

Future cash requirements – excluding CPILP

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. Capital Power's estimated cash requirements for the nine months ended December 31, 2011, excluding CPILP's cash requirements and cash requirements for acquisitions, are expected to include approximately $296 million for capital expenditures, approximately $45 million for CPLP distributions to EPCOR, subject to approval by the CPLP Board of Directors, approximately $38 million for Capital Power's quarterly common share dividends, subject to approval by the Capital Power Corporation Board of Directors, and approximately $4 million for its quarterly preferred share dividends. The current portion of long-term debt on the statement of financial position of $235 million is primarily comprised of $233 million payable to EPCOR, of which $33 million is payable in June 2011 and $200 million in November 2011.

The Company expects to fund the construction of the Quality Wind and Port Dover & Nanticoke wind projects using existing bank credit facilities. Once construction is complete, the Company expects to put long-term financing in place while maintaining the Company's overall leverage in the range of 40% to 50%. The Company's other cash requirements identified above are expected to be funded with cash on hand, cash provided by operating activities and use of existing bank credit facilities. The Company's acquisitions in the second quarter are expected to be funded with the net proceeds from the March 2011 $232 million equity issue and use of existing credit facilities. See Significant Events.

The Company's two short form base shelf prospectuses provide, market conditions permitting, the Company with the ability to obtain new debt and equity capital from external markets at the time of a requirement for a major investment of capital. Under the short form base shelf prospectuses, Capital Power may raise up to $1 billion by issuing common shares, or subscription receipts exchangeable for common shares or other securities of the Company, and up to $1 billion by issuing medium-term notes with maturities of not less than one year. Currently, CPLP has $547 million of equity and $400 million of debt available under these short form base shelf prospectuses. Both shelf prospectuses expire in May 2012.

Future cash requirements – CPILP

The following estimates of future cash requirements are subject to variable factors including those discussed in Forward-looking Information. CPILP's estimated cash requirements for the nine months ended December 31, 2011 are expected to include approximately $23 million for capital expenditures, approximately $73 million for distributions subject to approval by the CPILP Board of Directors and approximately $10 million for preferred share dividends of a subsidiary company. The amount of distributions will vary depending on the number of unitholders who opt under CPILP's distribution reinvestment program to accumulate additional units in lieu of cash distributions. If CPILP's total cash requirements for the remainder of 2011 remain as planned, it is expected that the sources of capital will be cash on hand, cash provided by operating activities and use of existing credit facilities.

CPILP's short form base shelf prospectus, market conditions permitting, provides the partnership with the ability to obtain new debt and equity capital from external markets at an aggregate amount of up to $600 million. This base shelf prospectus expires in August 2012.

Financial market stability remains an issue and if instability in the Canadian and U.S. financial markets were to return, it may adversely affect Capital Power's ability to raise new capital, to meet its financial requirements and to refinance indebtedness under existing credit facilities and debt agreements at their maturity dates. In addition, Capital Power has credit exposure with a number of counterparties to various agreements, most notably its PPA, trading and supplier counterparties. While the Company continues to monitor its exposure to its significant counterparties, there can be no assurance, particularly in light of the current economic environment, that all counterparties will be able to meet their commitments.

Contractual Obligations

Other than the commitments related to the acquisition of the three New England power plants and interest payments on the $300 million medium-term notes issued in April 2011, as described under Significant and Subsequent Events, there were no changes to the Company's purchase obligations, commitments or contingencies since December 31, 2010, including payments for the next five years and thereafter, that would be material to the Company's business or financial position. For further information on these obligations, refer to the Company's December 31, 2010 MD&A, filed on SEDAR at www.sedar.com.

Off-balance Sheet Arrangements

As at March 31, 2011, the Company had no off-balance sheet arrangements.

Related Party Transactions

EPCOR, including its subsidiaries, and its sole shareholder The City of Edmonton, are the only related parties with which the Company had material transactions in the three months ended March 31, 2011. At March 31, 2011, EPCOR owned 47.416 million exchangeable limited partnership units of CPLP and 47.416 million accompanying special voting shares and one special limited voting share in the capital of Capital Power Corporation.

The Company's long-term debt payable to EPCOR, which was also issued in connection with the Reorganization, was $619 million at March 31, 2011 compared with $869 million at March 31, 2010. The interest incurred on this debt was $10 million for the three months ended March 31, 2011 and $15 million for the corresponding period in 2010, of which $8 million and $10 million, respectively, was capitalized as property, plant and equipment for construction work in progress over the corresponding periods. The remainder was included in finance expense.

The Company's revenues for power sold to EPCOR for resale to its customers were $129 million for the three months ended March 31, 2011 compared with $102 million for the corresponding period in 2010. The Company's revenues for power sold to the City of Edmonton were $9 million for the three months ended March 31, 2011 and $8 million for the three months ended March 31, 2010. The Company's purchase of distribution and transmission services from EPCOR was $5 million and $6 million for the three months ended March 31, 2011 and March 31, 2010, respectively. The Company also had various transactions with EPCOR pursuant to the agreements which provide for the continuity of operations and services following the separation of the business of Capital Power from EPCOR. All of the above transactions were in the normal course of operations and were recorded at the exchange values which were based on normal commercial rates.

The balances outstanding at March 31, 2011 and March 31, 2010 resulting from transactions with EPCOR including its subsidiaries, and The City of Edmonton were as follows:

(unaudited, $ millions)	March 31, 2011	March 31, 2010
Statement of Financial Position		
Trade and other receivables	$53	$40
Other assets	7	7
Property, plant and equipment	7	10
Provisions (current and non-current)	6	-
Trade and other payables and accrued interest on debt	28	16
Loans and borrowings (including current portion)	619	869

Business Risks

There have been no material changes in the three months ended March 31, 2011 to the Company's business and operational risks as provided in the Company's December 31, 2010 MD&A.

International Financial Reporting Standards

Capital Power's March 31, 2011 condensed interim consolidated financial statements are the Company's first condensed interim consolidated financial statements prepared in accordance with International Accounting Standard (IAS) 34 Interim Financial Reporting. The comparative periods included in these financial statements have been restated to IFRS and the Company has applied IFRS 1 First-time Adoption of International Financial Reporting Standards. The Company's previously issued interim and financial reports for periods prior to and including the year ended December 31, 2010, were prepared in accordance with previous CGAAP.

The following tables provide a reconciliation of equity for comparative periods and of equity at the date of transition reported under previous CGAAP to those reported under IFRS.

(unaudited, $millions)	As at January 1, 2010		
	Attributable to shareholders	Non-controlling interests	Total equity
Previous CGAAP	$ 489	$ 2,046	$ 2,535
Adjustments:			
IAS 16 Property, plant and equipment and IAS 37 Provisions	(2)	(11)	(13)
IAS 36 Impairments	(6)	(44)	(50)
IFRS 1 First time adoption of IFRS	5	48	53
Other impacts	7	84	91
IFRS	$ 493	$ 2,123	$ 2,616

(unaudited, $millions)	As at March 31, 2010		
	Attributable to shareholders	Non-controlling interests	Total equity
Previous CGAAP	$ 495	$ 2,075	$ 2,570
Adjustments:			
IAS 16 Property, plant and equipment and IAS 37 Provisions	(4)	(19)	(23)
IAS 36 Impairments	(6)	(43)	(49)
IFRS 1 First time adoption of IFRS	4	45	49
Other impacts	10	85	95
IFRS	$ 499	$ 2,143	$ 2,642

(unaudited, $millions)	As at December 31, 2010		
	Attributable to shareholders	Non-controlling interests	Total equity
Previous CGAAP	$ 824	$ 1,754	$ 2,578
Adjustments:			
IAS 16 Property, plant and equipment and IAS 37 Provisions	(1)	(22)	(23)
IAS 36 Impairments	(4)	(108)	(112)
IFRS 1 First time adoption of IFRS	3	42	45
Other impacts	11	113	124
IFRS	$ 833	$ 1,779	$ 2,612

The following tables provide a reconciliation of the Company's total comprehensive income for the comparative period under previous CGAAP to those reported for that period and the year ended December 31, 2010 under IFRS.

(unaudited, $millions)	Three months ended March 31, 2010		
	Attributable to shareholders	Attributable to non-controlling interests	Total comprehensive income
Previous CGAAP	$ 13	$ 60	$ 73
Adjustments:			
IAS 16 Property, plant and equipment and IAS 37 Provisions	(2)	(8)	(10)
IAS 36 Impairments	1	1	2
IFRS 1 First time adoption of IFRS	(1)	(3)	(4)
Other impacts	1	1	2
IFRS	$ 12	$ 51	$ 63

(unaudited, $millions)	Year ended December 31, 2010		
	Attributable to shareholders	Attributable to non-controlling interests	Total comprehensive income
Previous CGAAP	$ 5	$ 75	$ 80
Adjustments:			
IAS 16 Property, plant and equipment and IAS 37 Provisions	2	(10)	(8)
IAS 36 Impairments	3	(65)	(62)
IFRS 1 First time adoption of IFRS	(1)	(7)	(8)
Other impacts	-	18	18
IFRS	$ 9	$ 11	$ 20

IAS 16 Property, plant and equipment (PP&E)

IFRS are more specific with respect to the level at which components of assets are to be accounted for. The appropriate components have been identified and the most significant difference from previous CGAAP is that overhaul costs are capitalized under IFRS. Additionally, certain costs relating to the Genesee mine that were previously capitalized under CGAAP have been expensed under IFRS due to componentization. The contract between the Genesee mine operator and the Company requires Capital Power to fully fund the operating activities of the mine, including depreciation, whereas capital asset funding is shared between the two parties. As a result, certain costs that were previously capitalized would have been expensed under the requirements of IAS 16 and fully funded by Capital Power. This has resulted in the Company recording transitional adjustments to record deferred revenue and other liabilities as well as adjustments to align the two parties' accounting policies.

IAS 37 Provisions

In accordance with IAS 37, provisions are required to be measured at the best estimate of the expected expenditure, such as for an asset retirement, using discount rates appropriate for each liability. Under previous CGAAP such provisions were measured at fair value. Under IFRS, provisions are re-measured at each reporting period for any changes in cash flow estimates, timing of decommissioning activity and discount rates. Accordingly, the Company re-measured its provisions using revised cash flow estimates for the Genesee mine asset retirement obligation and for revised discount rates for all of its plant decommissioning liabilities. The Company also re-measured amounts provided for the unavoidable costs of its Alberta retail and commercial natural gas contracts using revised cash flow assumptions and discount rates.

IAS 36 Impairments

The Company reviewed the recoverable amount for its cash generating units (CGUs) including any goodwill, in accordance with IAS 36, at both the date of transition to IFRS and in the third quarter of 2010. For these CGU's, management assessed whether there were any triggering events indicating possible impairment at December 31, 2010. The recoverable amounts were calculated at the fair value less cost to sell, using the Company's long term planning discounted cash flow models. Under previous CGAAP, the carrying amounts were compared to the undiscounted cash flows and if the undiscounted cash flows exceeded carrying value then no further steps were taken. IAS 36 also requires that impairment testing be done at a CGU level and requires that goodwill be allocated to the CGU and included in the impairment test for each plant. Some CGUs consist of a single plant resulting in more CGUs subject to impairment testing under IFRS than under previous CGAAP.

As a result of the changes to the determination of recoverable amounts and the allocation of the goodwill to the CGUs, the Company recognized $50 million of impairments at January 1, 2010. These impairments included $43 million for certain CPILP facilities due to the impact of weakening economic conditions in their respective markets and $7 million for the Company's management contracts with CPILP.

In the third quarter of 2010, impairment charges of $69 million related to CPILP's Calstock, Kapuskasing, North Bay and Tunis CGUs were recorded. These impairments were primarily due to lower expectations for throughput on the pipeline that provides the waste heat for these plants. The reduction in PP&E for impairment charges resulted in lower depreciation and amortization expense for these assets.

IFRS 1 First time adoption of IFRS

The Company elected under IFRS 1 to use fair value as the deemed cost of its PP&E for certain plants. As a result, the PP&E balance increased by $53 million, $49 million and $45 million at January 1, 2010, March 31, 2010 and December 31, 2010, respectively. Net income decreased by $1 million and $3 million for the three and twelve months ended March 31, 2010 and December 31, 2010, respectively due to higher depreciation and amortization on the increased PP&E balances.

IFRS 1 provides an election to deem any cumulative translation differences to be zero on transition to IFRS. As a result of the Company taking the IFRS 1 election to adjust the balance of its cumulative translation account to nil at the date of transition, $4 million was reclassified within equity, between accumulated other comprehensive income and retained earnings at January 1, 2010.

Under previous CGAAP, the Company recognized actuarial gains and losses into income or loss using the corridor approach whereby amounts that exceeded the corridor were recognized into income or loss over the average remaining service period of the active employees. At the date of transition, all previously unrecognized cumulative actuarial gains and losses were reclassified within equity and recognized in retained earnings.

IFRS 1 provides an optional election to adopt a simplified approach for decommissioning liabilities, whereby the Company can elect to not calculate retrospectively the effect of each change in estimate that occurred prior to the date of transition. The Company has elected to use the simplified approach.

Other impacts

In accordance with IAS 17, Leases, the Kingsbridge PPA was determined to be a finance lease due to IAS 17 and previous CGAAP having different qualitative guidelines in the determination of the classification of leases between operating and finance (or capital under previous CGAAP) resulting in a decrease in PP&E of $53 million, an increase in finance lease receivable of $64 million, an increase in trade and other receivables of $2 million and an increase in retained earnings of $13 million at January 1, 2010.

In accordance with IAS 31, Interests in Joint Ventures, the Company controls the Genesee mine joint venture and as a result the Company consolidated the non-controlling interest's share of the Genesee mine assets resulting in an increase in PP&E of $87 million, $87 million and $90 million at January 1, 2010, March 31, 2010 and December 31, 2010, respectively.

In accordance with IAS 39, Financial Instruments: Recognition and Measurement, financial assets available for sale must be measured at fair value. Under previous CGAAP, the investment in PERH was carried at the lower of historic cost and fair value while the investment is carried at fair value under IFRS. Accordingly, other financial assets were reduced by $3 million at January 1, 2010, changed by nil at March 31, 2010 and increased by $11 million at December 31, 2010. Unrealized fair value gains or losses are recorded in other comprehensive income.

In accordance with IAS 39, hedge effectiveness testing must incorporate the Company's credit risk, which resulted in immaterial changes in the ineffective portion of the change in the fair value of the Company's energy contracts.

Other impacts in the tables above also include the tax impact of the adjustments recognized.

Future Accounting Changes

A number of new standards, and amendments to standards and interpretations, are not yet effective for the quarter ended March 31, 2011 and have not been applied in preparing the unaudited condensed interim consolidated financial statements. The following standards and interpretations have been issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committees with effective dates relating to the annual periods starting on or after the effective dates as follows:

International Accounting Standards (IAS/IFRS)	Effective Date
IFRS 9 - Financial Instruments	January 1, 2013
IAS 12 - Income taxes	January 1, 2012

IFRS 9 applies to the classification and measurement of financial assets and financial liabilities. It is the first of three phases of a project to develop standards to replace IAS 39 Financial Instruments and was initiated in response to the crisis in financial markets. The amendments to IAS 12 relate to the measurement of deferred taxes for investment property, PP&E and intangible assets carried at fair value.

The extent of the impact of adoption of these standards and interpretations on the consolidated financial statements of the Company has not been determined.

Critical Accounting Estimates and Policies

In preparing the consolidated financial statements, management necessarily made estimates in determining transaction amounts and financial statement balances. The following are the Company's most significant accounting policies and the items for which critical estimates were made in the financial statements and should be read in conjunction with the notes to the unaudited condensed interim consolidated financial statements.

Revenue recognition under PPAs

Revenues from certain of the Company's power generation plants are recognized upon delivery of output or upon availability for delivery as prescribed by contractual arrangements. These contractual arrangements are also commonly referred to as PPAs. Revenues from certain PPAs are recognized at the lower of (1) the MWhs made available during the period multiplied by the billable contract price per MWh, and (2) an amount determined by the MWhs made available during the period, multiplied by the average price per MWh over the term of the contract. Any excess of the contract price for the period over the average price is recorded as deferred revenue.

Financial instruments

The Company is required to estimate the fair value of certain assets and obligations for determining the valuation of certain financial instruments.

Fair values of derivative instruments are determined, when possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask or closing market prices as appropriate, in the most advantageous active market for that instrument. When traded markets are not considered to be sufficiently active or do not exist, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. The Company may also rely on price forecasts prepared by third party market experts to estimate fair value when there are limited observable prices available. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates and maximize, when available, the use of external readily observable market data including future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rates, counterparty credit risk, the Company's own credit risk, and volatility. When a valuation technique utilizes unobservable market data, no inception gains or losses are recognized, until market quotes or data becomes observable.

Non-financial assets

Depreciation and amortization allocate the cost of assets and their components over their estimated useful lives on a systematic and rational basis. Depreciation and amortization also include amounts for future decommissioning costs. Estimating the appropriate useful lives of assets requires significant judgement and is generally based on estimates of the life characteristics of common assets.

In the first quarter of 2011 management performed a review of the useful life of the Company's coal plants and determined that the useful life did not match common industry practices. As a result of an analysis against industry peers, historical averages and the Company's maintenance practices the expectations regarding the useful life of the coal plants had changed. As a result, effective January 1, 2011 the Company prospectively revised its estimate of the useful life of its coal plants from 35 years to 45 years. The change in expectation resulted in lower depreciation expense of $3 million in the first quarter of 2011.

The Company reviews the recoverability of non-financial assets subject to depreciation and amortization (property, plant and equipment and definite life intangible assets) when events or changes in circumstances may indicate or cause a non-financial asset's carrying amount to exceed its recoverable amount. The Company reviews the recoverability of goodwill and indefinite life intangibles on an annual basis. The asset's recoverable amount is the higher of its fair value less costs to sell and the present value of discounted expected future cash flows expected from the asset's use and eventual disposition. For the purpose of impairment testing, assets that cannot be tested individually are grouped together into a CGU, which is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or group of assets.

For determining purchase price allocations for business combinations, the Company is required to estimate the fair value of acquired assets and obligations. Goodwill is measured as the excess of the fair value of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. Goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the CGUs that are expected to benefit from the acquisition. An impairment loss, if any, would be recorded as the excess of the carrying amount of the asset over its recoverable amount, and in case of a CGU, is allocated first to reduce the carrying amount of goodwill allocated to the unit. An impairment loss is reversed if there is any indication that previously incurred losses no longer exist.

Estimates of fair value for goodwill and other asset impairments, and purchase price allocations for business combinations are primarily based on discounted cash flow projections techniques employing estimated future cash flows based on a number of assumptions and using an appropriate discount rate. The cash flow estimates will vary with the circumstances of the particular assets or CGU and will be based on, among other things, the lives of the assets, contract prices, estimated future prices, revenues and expenses, including growth rates and inflation, and required capital expenditures.

Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. The obligation is discounted using a discount rate that reflects current market assessments of the time value of money and the risks specific to the obligation for which the estimates of future cash flows have not been adjusted. The change in discount rate due to the passage of time is recognized as a finance expense, and is recorded over the estimated time period until settlement of the obligation. Provisions are reviewed and adjusted, when required, to reflect the current best estimate at the end of each reporting period.

The Company recognizes decommissioning provisions in the period in which a legal or constructive obligation is incurred. A corresponding decommissioning cost is added to the carrying amount of the associated property, plant and equipment, and it is depreciated over the estimated useful life of the asset. The Company has recorded decommissioning provisions for its power generation plants and the Genesee coal mine as it is obliged to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. Decommissioning provisions for the coal mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation. Accretion of the liability is recorded in finance expense.

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under contract. The provision is measured at the present value of the lower of expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on the assets associated with that contract.

Income taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, current income taxes for the current or prior periods are recognized and measured at the amount expected to be recovered from or payable to the taxation authorities based on the tax rates that are enacted or substantively enacted by the end of the reporting period.

Deferred income tax assets and liabilities are recognized for the deferred tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases.

Deferred tax assets are generally recognized for all deductible temporary differences to the extent that it is probable that taxable income will be available against which those deductible temporary differences can be utilized. Such deferred tax assets and liabilities are not recognized if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable income nor the accounting income.

Deferred tax liabilities are recognized for taxable temporary differences associated with investments in subsidiaries, and interests in joint arrangements, except where the Company is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets arising from deductible temporary differences associated with such investments and interests are only recognized to the extent that it is probable that there will be sufficient taxable income against which to utilize the benefits of the temporary differences and they are expected to reverse in the foreseeable future.

Deferred income tax assets and liabilities are measured using enacted or substantively enacted rates of tax expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in net income in the period that includes the date of enactment or substantive enactment.

Current and deferred tax relating to items recognized directly in equity is recognized in equity and not in the consolidated statement of income.

Deferred income tax assets are reviewed to determine the likelihood that they will be realized from future taxable income. Estimates of the provision for current income taxes and deferred income taxes resulting from temporary tax differences might vary from actual amounts incurred.

Leases or arrangements containing a lease

The Company has entered into PPAs to sell power at predetermined prices. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the Company's property, plant and equipment in return for payment. Such types of arrangements may be classified as either finance or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property from the Company are classified as finance leases. PPAs that do not transfer all of the benefits and risks of ownership of property, plant and equipment are classified as either operating leases or executory contracts.

For those PPAs determined to be finance leases with the Company as the lessor, finance income related to leases or arrangements accounted for as finance leases is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is composed of minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying amount of the leased property. Unearned finance income is deferred and recognized in the consolidated statement of income over the lease term.

Payments received under PPAs classified as finance leases are segmented into those for the lease and those for other elements on the basis of their relative fair value. For those PPAs determined to be operating leases with the Company as the lessor, revenue is recognized on a straight line basis unless another method better represents the earning process.

The Company has exercised judgment in determining whether the risks and rewards of its generation assets which are subject to a PPA are transferred to the PPA buyer, in determining whether a lease exists and if so, whether the lease should be treated as a finance or operating lease.

Foreign currency translation

On consolidation the assets and liabilities of operations that have a functional currency that is different from the Company’s functional currency of Canadian dollars, principally on U.S. operations that have a functional currency of U.S. dollars, are translated into Canadian dollars at the exchange rates in effect at the date of the statement of financial position. Revenues and expenses are translated at average exchange rates prevailing during the period. The resulting translation gains and losses are deferred and included in accumulated other comprehensive income as part of translation gains and losses.

Transactions denominated in currencies other than the functional currency of the Company, or the subsidiary concerned, are translated at exchange rates in effect at the transaction date. At each reporting date monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect at the date of the statement of financial position. Other non-monetary assets are not retranslated unless they are carried at fair value. Revenues and expenses are translated at average exchange rates prevailing during the period. The resulting foreign exchange gains and losses are included in net income.

Consolidation of CPILP, CPLP and Genesee coal mine

While the Company indirectly owns only 29.4% (29.6% at December 31, 2010, 30.5% at January 1, 2010) of the outstanding units of CPILP and has an approximate 45.9% interest in CPLP (39.5% at December 31, 2010, 27.8% at January 1, 2010), it controls both CPILP and CPLP and therefore both CPILP and CPLP are treated as subsidiaries of the Company. Accordingly, CPILP and CPLP are consolidated in the financial statements of the Company. In addition, while the Company owns 50% of the assets of the Genesee mine joint venture it is deemed to control the assets. As a result, the Genesee coal mine is consolidated in the financial statements.

Non-controlling interests in subsidiaries are identified separately from the Company’s equity. The non-controlling interests may be initially measured either at fair value or at the non-controlling interests’ proportionate share of the fair value of the acquired business’ identifiable net assets. The choice of measurement basis is made on an acquisition-by-acquisition basis. Subsequent to acquisition, the carrying amount of non-controlling interests is the amount of those interests at initial recognition plus the non-controlling interest’s share of subsequent changes in equity. Total comprehensive income is attributed to non-controlling interests even if this results in the non-controlling interests having a deficit balance.

Financial Instruments

The Company's derivative instruments assets and liabilities used for risk management purposes are measured at fair value and consist of the following:

(unaudited, $ millions)	Energy cash flow hedges	Energy non-hedges	Foreign exchange non-hedges	Interest rate non-hedges	Total
Total derivative instruments net assets (liabilities) as at March 31, 2011	$ (119)	$ 10	$ 34	$ 4	$ (71)

At March 31, 2011, the fair value of energy derivative instruments designated and qualifying for hedge accounting was a net liability of $119 million which primarily reflected the impact of decreased future prices for natural gas relative to natural gas supply contract prices.

At March 31, 2011 the fair value of energy derivative instruments not designated as hedges for accounting purposes was a net asset of $10 million, which primarily reflected the impact of changes in the forward Alberta power prices on the Alberta power portfolio.

At March 31, 2011, the fair value of the Company's forward foreign currency contracts was a net derivative instrument asset of $34 million, which primarily reflected the impact of strengthening future prices for the Canadian dollar relative to the U.S. dollar on forward foreign exchange sales contracts used to hedge U.S. dollar denominated revenues. As at March 31, 2011, $333 million (US$297 million) of expected future net U.S. dollar cash flows from CPILP's U.S. plants for 2011 to 2016 were economically hedged at a weighted average exchange rate of $1.12 to US$1.00. As at March 31, 2011, $311 million (US$304 million) of expected future net U.S. dollar cash flows for CPLP capital expenditure commitments for 2011 were economically hedged at a weighted average exchange rate of $1.02 to US$1.00.

At March 31, 2011, the fair value of the Company's forward bond sale contracts was a net derivative instrument asset of $4 million. These contracts were entered into in the first quarter of 2011 to hedge exposure to interest rate risk on the $300 million medium-term notes issue. See Subsequent Events. The unrealized changes in the fair value of these contracts for first quarter of 2011 were recognized in financing expenses, as discussed under Consolidated Other Expenses.

For the three months ended March 31, 2011 and March 31, 2010, losses net of income taxes on derivative instruments designated as cash flow hedges, of $53 million and $17 million respectively, were recorded in other comprehensive income for the effective portion of cash flow hedges. Realized gains, net of income taxes, for the three months ended March 31, 2011 of $3 million and losses, net of income taxes, for the three months ended March 31, 2010 of $6 million, were reclassified to energy purchases and revenues as appropriate. For the three months ended March 31, 2011 and March 31, 2010, the change in the fair value of the ineffective portion of hedging derivatives recognized in the statement of income, before non-controlling interests, was a $1 million loss and $1 million gain, respectively.

Internal Control over Financial Reporting

There were no changes in the Company's internal controls over financial reporting that occurred during the three months ended March 31, 2011 that have materially affected, or are reasonably likely to materially affect the Company's internal control over financial reporting. The Company's transition to IFRS in the period did not result in any significant changes to the Company's internal controls.

Forward-looking Information

Certain information in this MD&A is forward-looking within the meaning of Canadian securities laws as it relates to anticipated financial performance, events or strategies. When used in this context, words such as will, anticipate, believe, plan, intend, target, and expect or similar words suggest future outcomes.

Forward-looking information in this MD&A includes, among other things, information relating to: (i) expectations regarding timing of anticipated updates on the review of strategic alternatives for CPILP; (ii) expectations for the

Company's and CPILP's sources of capital and use, adequacy and availability of committed bank credit facilities and potential future borrowings; (iii) the Company's and CPILP's cash requirements for 2011, including interest and principal repayments, capital expenditures, distributions and dividends; (iv) expectations regarding repair costs and ability to recover costs under warranty for the outage of Clover Bar Energy Centre Unit 3; (v) expectations regarding timing of spending on the Port Dover & Nanticoke project and the impact on the commercial operation date and total project cost; (vi) expectations regarding the impact and timing of Keephills 3 coming on-line on earnings and normalized earnings per share for 2011; (vii) expected total capital project costs and expenditures as well as expected project completion dates and expected payments under contractual obligations; (viii) expected funding of the Quality Wind and Port Dover & Nanticoke wind projects during construction and once completed while maintaining overall leverage in the range of 40% - 50%; (ix) expected impact of IFRS transition adjustments on earnings in future periods; (x) the expected impact on depreciation as a result of the extension in useful life of the Genesee and Keephills 3 plants; (xi) expected impact on capitalization and full year depreciation as a result of maintenance costs which are capitalized under IFRS; (xii) expected impact on earnings after depreciation expense and before financing and income tax expenses as a result of the three New England plant acquisitions in 2011; (xiii) expected impact on interest due to the issuance of $300 million medium-term notes debentures in April 2011 and expected use of proceeds; (xiv) expectations regarding normalized earnings per share for 2011 being approximately $1.40 per common share and expectations regarding full year earnings in 2011; (xv) expectations regarding Alberta power prices for 2011; (xvi) expectations regarding total contribution of the New England plant acquisitions to the Company's committed capital in 2011; (xvii) expectations regarding allocated capital, plant availability targets, capital expenditures for plant maintenance and the Genesee mine extension, and total shareholder return in 2011; (xviii) expectations regarding the impact of Clover Bar Energy Centre Unit 3 being offline on plant availability and on financial results; (xix) expected timing of return of service date of Clover Bar Energy Centre Unit 3 and expected timing of Unit 2 outage in 2011, and estimated business interruption insurance recovery from the Unit 2 outage in 2010; (xx) expectations regarding the timing and impact on capitalization, depreciation, and maintenance expense of the scheduled maintenance outage at Genesee 1 in 2011; (xxi) expectations regarding the impact of the acquisition of the New England facilities on EBITDA and depreciation expense in 2011, and earnings in 2012 and subsequent years; (xxii) expectations regarding the purchase price and timing of closing of the Tiverton and Rumford acquisition; (xxiii) expectations regarding the interim and permanent financing of the New England plant acquisitions using a combination of debt and equity; (xxiv) expectations regarding the ability to attain the goal of 10,000 MW of assets by 2020; (xxv) expectations that the Tiverton, Rumford and Bridgeport power plants will provide Capital Power with the foundation of a networked hub in the U.S. Northeast; (xxvi) expectations that the Tiverton, Rumford and Bridgeport power plants will contribute to a balanced portfolio of contracted and merchant assets; (xxvii) expectations in respect of new PPAs at the North Carolina facilities and expectations with respect to CPILP's long-term outlook for the North Carolina plants; (xxviii) expectations that Bridgeport can maximize energy and ancillary services revenue through operational flexibility; (xxix) expectations regarding the Company's strategy, including the Company's expectation to commit at least $1.5 billion of new development or acquisitions in 2011; (xxx) expectations regarding CPILP's income taxes in the third and fourth quarter of 2011; and (xxxi) expectations regarding the impact of the delay in commercial operation date of Keephills 3 on capital costs, net income and cash from operating activities.

These statements are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions and expected future developments and other factors it believes are appropriate. The material factors and assumptions used to develop these forward-looking statements include, but are not limited to: (i) the operation of the Company's facilities; (ii) power plant availability and dispatch, including Sundance which is subject to an acquired PPA; (iii) the Company's financial position and credit facilities and sources of funding; (iv) the Company's assessment of commodity and power markets, including power prices for 2011; (v) the Company's assessment of the markets and regulatory environments in which it operates; (vi) weather; (vii) availability and cost of labour and management resources; (viii) performance of contractors and suppliers; (ix) availability and cost of financing; (x) foreign exchange rates; (xi) management's analysis of applicable tax legislation; (xii) currently applicable and proposed tax laws will not change and will be implemented; (xiii) currently applicable and proposed environmental regulations will be implemented; (xiv) counterparties will perform their obligations; (xv) renewal and terms of PPAs; (xvi) ability to successfully integrate and realize benefits of its acquisitions; (xvii) ability to implement strategic initiatives which will yield the expected benefits; (xviii) ability to obtain necessary regulatory approvals for development projects; (xix) the Company's assessment of capital markets, common share ownership distribution, and ability to complete future share and debt offerings; (xx) locations of projects and the areas of which they will be developed, including the availability and use of certain optioned lands; (xxi) costs of construction and development; (xxii) current risk management strategies including hedges will be in place; and (xxiii) factors and assumptions noted under Outlook in respect of the forward looking statements and information noted in that section.

Whether actual results, performance or achievements will conform to the Company's expectations and predictions is subject to a number of known and unknown risks and uncertainties which could cause actual results and experience to differ materially from the Company's expectations. Such risks and uncertainties include, but are not limited to, risks relating to: (i) operation of the Company's facilities; (ii) power plant availability and performance, including unplanned plant outages at facilities of other market participants; (iii) unanticipated maintenance and other expenditures; (iv) availability and price of energy commodities; (v) electricity load settlement; (vi) regulatory and government decisions including changes to environmental, financial reporting and tax legislation; (vii) weather and economic conditions; (viii) competitive pressures; (ix) construction; (x) availability and cost of financing; (xi) foreign exchange; (xii) availability and cost of labour, equipment and management resources; (xiii) performance of counterparties, partners, contractors and suppliers in fulfilling their obligations to the Company; (xiv) developments in the North American capital markets; (xv) compliance with financial covenants; (xvi) ability to successfully realize the benefits of acquisitions and investments; (xvii) the tax attributes of and implications of any acquisitions; (xviii) the outcome of CPILP's strategic review; (xix) ability to secure new contracts and terms of such contracts; and (xx) risks and uncertainties noted under Outlook in respect of the forward looking information and statements noted in that section. See also Business Risks in the Company's December 31, 2010 annual MD&A. If any such risks actually occur, they could materially adversely affect the Company's business, financial condition or results of operations. In that case the trading price of the Company's common shares could decline, perhaps materially.

This MD&A includes the following updates to previously disclosed forward-looking statements: (i) expectations regarding capital expenditures have been revised to reflect a change in the timing of spending on the Port Dover & Nanticoke project from 2011 to 2012; (ii) expectations regarding normalized earnings per share have been updated to include revised expectations regarding Alberta power prices in 2011, IFRS transition adjustments, a change in the estimated useful life of the Genesee and Keephills 3 plants, the addition of the three New England plants, and higher financing costs and equity dilution as a result of the medium-term debt issuance and equity offering, respectively, in the first quarter of 2011; (iii) estimates for capital expenditures in 2011 have been updated to include changes in the estimated plant maintenance capital expenditures due to the impact of capitalizing major maintenance costs under IFRS, the inclusion of maintenance capital expenditures for the three New England plants, and the delay in spending on the Port Dover and Nanticoke project; (iv) Capital Power's and EPCOR's expected share of net income has been updated to include the changes to the current common share ownerships as a result of the 9.3 million common shares equity offering in March 2011; (v) the expected commercial operation date for Keephills 3 has been revised from the second quarter to the third quarter of 2011; and (vi) capital expenditures on Keephills 3 has been revised to include additional costs associated with cleaning of the boiler.

Readers are cautioned not to place undue reliance on any such forward-looking statements, which speak only as of the date made. Forward-looking statements are provided for the purpose of providing information about management's current expectations, and plans relating to the future. Readers are cautioned that such information may not be appropriate for other purposes. The Company does not undertake or accept any obligation or undertaking to release publicly any updates or revisions to any forward-looking statements to reflect any change in the Company's expectations or any change in events, conditions or circumstances on which any such statement is based, except as required by law.

Quarterly Information

Quarterly revenues, net income and funds provided by operating activities are affected by seasonal weather conditions, fluctuations in U.S. dollar exchange rates relative to the Canadian dollar, power and natural gas prices, planned and unplanned plant outages, as well as items outside the normal course of operations. Net income is also affected by changes in the fair value of the Company's derivative power, natural gas, foreign exchange and forward bond sale contracts, and natural gas held for trading.

Financial highlights

(unaudited, $millions except earnings (loss) per share)	Three months ended						
	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009[3]	Sept 30, 2009[3]
Revenues and other income[2]	458	437	511	313	501	497	511
Gross income	167	205	233	117	217	216	218
EBITDA[1]	82	96	80	37	169	116	140
Net income (loss)	14	22	(3)	(34)	92	39	80
Net income attributable to shareholders	3	(3)	16	(8)	12	7	14
Earnings (loss) per share	$0.06	$(0.13)	$0.73	$(0.37)	$0.55	$ 0.33	$ 0.64
Normalized earnings per share[1]	$0.33	$0.21	$0.64	$0.05	$0.51	$ 0.18	$ 0.42

(1) The consolidated financial information, except for EBITDA and normalized earnings per share, has been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

(2) Revenues for the three months ended September 30, 2009 have been restated for a reclassification which resulted in a reduction in each of revenue and energy purchases by $14 million. The restatement had no impact on gross income, EBITDA or net income and the presentation is consistent with subsequent periods.

(3) The results for the third and fourth quarters of 2009 have been prepared in accordance with previous CGAAP.

Generation volume and plant availability information

(unaudited, GWh)	Three months ended						
Electricity generation[1]	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009	Sept 30, 2009
Alberta commercial plants							
Genesee 3	482	272	475	432	483	484	470
Joffre	98	82	67	93	41	73	89
Clover Bar Energy Centre 1, 2 and 3	162	179	37	102	43	9	16
Taylor Coulee Chute	-	1	7	3	-	2	12
Clover Bar Landfill Gas	8	9	9	10	10	10	9
Weather Dancer	-	-	-	-	-	-	-
	750	543	595	640	577	578	596
Alberta contracted plants							
Genesee 1	768	854	841	780	813	618	837
Genesee 2	831	826	824	571	825	817	801
	1,599	1,680	1,665	1,351	1,638	1,435	1,638
Ontario and British Columbia contracted plants							
Kingsbridge 1	31	39	18	22	26	32	14
Miller Creek	5	7	46	35	7	14	47
Brown Lake	14	14	5	11	13	15	11
Island Generation	52	273	-	-	-	-	-
	102	333	69	68	46	61	72
Total plants excluding CPILP plants	**2,451**	**2,556**	**2,329**	**2,059**	**2,261**	**2,074**	**2,306**
CPILP plants	1,139	1,311	1,306	1,128	1,268	1,407	1,228
Total plants	**3,590**	**3,867**	**3,635**	**3,187**	**3,529**	**3,481**	**3,534**

(1) Electricity generation reflects the Company's share of plant output.

(unaudited)	Three months ended						
Generation plant availability[1]	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009	Sept 30, 2009
Alberta commercial plants							
Genesee 3	100%	56%	99%	96%	100%	99%	97%
Joffre	99%	99%	98%	84%	100%	94%	96%
Clover Bar Energy Centre 1, 2 and 3	65%	95%	63%	52%	72%	98%	96%
Taylor Coulee Chute	100%	100%	100%	90%	98%	66%	100%
Clover Bar Landfill Gas	95%	88%	92%	96%	96%	94%	90%
Weather Dancer	0%	0%	0%	0%	83%	0%	55%
	87%	83%	86%	76%	90%	97%	96%
Alberta contracted plants							
Genesee 1	92%	100%	100%	100%	99%	74%	100%
Genesee 2	100%	97%	97%	75%	99%	97%	95%
	96%	98%	99%	87%	99%	85%	97%
Ontario and British Columbia contracted plants							
Kingsbridge 1	98%	100%	99%	100%	99%	100%	99%
Miller Creek	78%	12%	96%	96%	37%	97%	88%
Brown Lake	100%	99%	93%	99%	97%	99%	97%
Island Generation	99%	99%	-	-	-	-	-
	97%	91%	97%	98%	74%	99%	94%
Average excluding CPILP plants[2]	**93%**	**91%**	**93%**	**83%**	**93%**	**92%**	**97%**
CPILP plants[2]	92%	97%	97%	90%	95%	92%	93%
Average all plants[2]	**92%**	**95%**	**95%**	**86%**	**94%**	**92%**	**95%**

(1) Plant availability represents the percentage of time in the period that the plant was available to generate power, regardless of whether it was running, and therefore is reduced by planned and unplanned outages.

(2) Average generation plant availability is an average of individual plant availability weighted by owned or operated capacity.

The Company's target for plant availability excluding CPILP plants for 2011 is 94%. In the first quarter of 2011, 93% was achieved for this performance measure, reflecting the outage at Clover Bar Energy Centre Unit 3 which has been offline since January 15, 2011 due to blade damage in its high pressure compressor.

Results by plant category

(unaudited, $millions)	Three months ended						
	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009[2]	Sept 30, 2009[2][3]
Revenues and other income							
Alberta commercial plants and portfolio optimization	$ 266	$ 237	$ 247	$ 197	$ 235	$ 248	$ 238
Alberta contracted plants	77	76	72	57	73	61	70
Ontario/British Columbia contracted plants	13	12	3	3	3	4	4
CPILP plants	128	139	130	116	139	130	123
Other portfolio activities	34	26	19	22	43	40	23
Corporate	6	6	7	10	6	-	-
Inter-plant category transaction eliminations	(20)	(15)	(16)	(18)	(15)	(9)	(10)
	504	481	462	387	484	474	448
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading							
- CPLP	(49)	(55)	38	(55)	12	15	30
- CPILP	3	11	11	(19)	5	8	33
	(46)	(44)	49	(74)	17	23	63
	$ 458	**$ 437**	**$ 511**	**$ 313**	**$ 501**	**$ 497**	**$ 511**
Gross income							
Alberta commercial plants and portfolio optimization	$ 50	$ 58	$ 69	$ 59	$ 65	$ 53	$ 50
Alberta contracted plants	62	56	59	42	58	48	58
Ontario/British Columbia contracted plants	13	12	3	3	3	4	4
CPILP plants	72	85	76	68	77	74	77
Other portfolio activities	9	3	13	6	15	12	8
Corporate	6	6	7	10	6	-	-
Inter-plant category transaction eliminations	(13)	(15)	(15)	(17)	(14)	(9)	(8)
	199	205	212	171	210	182	189
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading							
- CPLP	(34)	(14)	14	(36)	9	26	16
- CPILP	2	14	7	(18)	(2)	8	13
	(32)	-	21	(54)	7	34	29
	$ 167	**$ 205**	**$ 233**	**$ 117**	**$ 217**	**$ 216**	**$ 218**
EBITDA[1]							
Alberta commercial plants and portfolio optimization	$ 38	$ 45	$ 57	$ 46	$ 53	$ 42	39
Alberta contracted plants	47	41	46	29	44	25	45
Ontario/British Columbia contracted plants	10	8	2	2	2	3	3
CPILP plants	45	39	(1)	43	49	39	48
Other portfolio activities	-	(5)	5	(5)	6	(1)	2
Corporate	(26)	(33)	(50)	(24)	(20)	(26)	(25)
Inter-plant category transaction eliminations	-	-	-	-	-	-	(1)
	114	95	59	91	134	82	111
Unrealized fair value changes in derivative instruments and natural gas inventory held for trading							
- CPLP	(34)	(15)	14	(36)	9	26	16
- CPILP	2	14	7	(18)	(2)	8	13
	(32)	(1)	21	(54)	7	34	29
Gains on acquisitions and disposals	-	2	-	-	28	-	-
	$ 82	**$ 96**	**$ 80**	**$ 37**	**$ 169**	**$ 116**	**$ 140**

(1) The results by plant category, except for EBITDA, have been prepared in accordance with IFRS. See Non-IFRS Financial Measures.

(2) The results for the third and fourth quarter of 2009 have been prepared in accordance with previous CGAAP.

(3) Revenues and energy purchases for the third quarter of 2009 have been restated. See Quarterly Information - Financial Highlights.

(unaudited, $/MWh)	Three months ended						
Alberta power prices	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	Jun 30, 2010	Mar 31, 2010	Dec 31, 2009	Sept 30, 2009
Average Alberta power spot price	$ 82	$ 46	$ 36	$ 81	$ 41	$ 46	$ 50
Capital Power's Alberta portfolio's average realized power price	64	64	66	66	67	57	54

Factors impacting the 2011 first quarter results

The Company's plant availability decreased to 92% in the first quarter of 2011 primarily due to the blade damage outage at Clover Bar Energy Centre Unit 3.

The realized price for the Alberta commercial plants and portfolio optimization in the first quarter of 2011 was $64/MWh which was $18/MWh lower than the average Alberta power price of $82/MWh for the period. The increase in the average Alberta power price was the result of cooler weather than normal and changes in supply due to the shut down of two large coal plants and derates of other units in the region. The significant increases in Alberta power prices in the first quarter of 2011 had an unfavourable impact on the Company's Alberta portfolio position but provided opportunities to dispatch the Clover Bar Energy Centre and Joffre facility.

The increase in revenues, gross income and EBITDA for the Alberta contracted plants were primarily due to higher rolling average power prices during the first quarter of 2011.

The fair value of CPLP's derivative instruments decreased in the first quarter primarily due to the impact of increased Alberta forward power prices on the portfolio position.

Corporate EBITDA was lower primarily due to professional fees for the New England plants acquisitions and a $2 million unrealized decrease in the fair value of foreign exchange contracts. The foreign exchange contracts were entered into in the first quarter of 2011 in anticipation of future U.S. cash payments for the acquisitions of the three New England power plants. See Significant and Subsequent Events.

Unrealized changes in the fair value on three $100 million forward bond contracts entered into in the first quarter of 2011 and the reversal of unrealized losses relating to 2010 forward bond contracts resulted in a net unrealized gain of $10 million in the first quarter of 2011. This was partly offset by a $2 million loss realized on the settlement of two $100 million forward bond sale contracts.

Factors impacting results for the previous quarters

Significant items which impacted results for the previous quarters were as follows:

The realized price for the Alberta commercial plants and portfolio optimization in the fourth quarter of 2010 was $64/MWh which was $18/MWh higher than the average Alberta power price of $46/MWh for the period. Increases in Alberta power spot prices and volatility in those prices provided opportunities to dispatch the Alberta commercial peaking and mid-merit plants and thereby contribute to revenues and EBITDA. This increased generation was offset by reduced generation from Genesee 3 as a result of a 42-day scheduled maintenance outage. The fair value of CPLP's derivative instruments decreased in the fourth quarter primarily due to the impact of increased Alberta forward power prices on the portfolio position. The increase in the fair value of CPILP's derivative instruments primarily reflected the impact of strengthening future prices for the Canadian dollar relative to the U.S. dollar on foreign exchange contracts. In December 2010, a subsidiary of EPCOR exchanged 9,209,000 of its exchangeable limited partnership units in CPLP for common shares of Capital Power on a one-for-one basis reducing EPCOR's ownership interest in CPLP to approximately 60.5% from its initial interest of 72.2%.

The realized price for the Alberta commercial plants and portfolio optimization in the third quarter of 2010 was $66/MWh which was $30/MWh higher than the average Alberta power price of $36/MWh for the period. The expected recovery of $8 million in business insurance proceeds relating to the outage of Clover Bar Energy

Centre Unit 2 from March 8 until September 22 was recorded in the third quarter of 2010 and included in the results for Alberta commercial plants and portfolio optimization. CPILP's EBITDA included asset impairment charges. Corporate EBITDA included $7 million for the recognition of the obligation to EPCOR for operations and maintenance costs for the Rossdale plant and assets over the ten-year period ending in 2019, and a write down of the fair value increments related to the asset impairment charges of CPILP's Ontario plants as a result of the transition to IFRS. Income taxes reflected the recognition of a future income tax liability relating to the investment in CPILP, as a result of the strategic alternatives review. Financing expenses for the third quarter of 2010 included $7 million of unrealized losses for the decrease in the fair value of two forward bond sale contracts that were entered into in the second quarter of 2010.

In the second quarter of 2010, the realized price for the Alberta commercial plants and portfolio optimization was $66/MWh which was $15/MWh lower than the average Alberta power price of $81/MWh for the period. High pricing and volatility of Alberta power spot prices resulted in higher than normal dispatch of the Alberta commercial peaking and mid-merit plants. The favourable impact of this increased generation on the EBITDA was partly offset by the impact of lower EBITDA from portfolio optimization strategies. The EBITDA for the Alberta contracted plants reflected availability penalties related to the 21-day scheduled outage at Genesee 2. The decrease in the fair value of derivative instruments primarily reflected the impact of increased Alberta forward power prices on CPLP's portfolio position and unrealized losses on CPILP's foreign exchange contracts due to weakening future prices for the Canadian dollar relative to the U.S. dollar.

In the first quarter of 2010, the realized price for the Alberta commercial plants and portfolio optimization was $67/MWh which was $26/MWh higher than the average Alberta power price of $41/MWh for the period. This favourable realized price was primarily a result of merchant trading of derivative sell contracts in the period.

In the fourth quarter of 2009, the planned outage at Genesee 1 resulted in availability penalty payments. The increase in the fair value of derivative instruments in the fourth quarter of 2009 reflected the impact of decreased forward Alberta power prices on CPLP's portfolio position and unrealized gains on CPILP's foreign exchange contracts due to strengthening future prices for the Canadian dollar relative to the U.S. dollar. An income tax recovery that was recognized in the third quarter was reclassified in the fourth quarter and included in the acquisition of assets from EPCOR since it related to periods prior to July 1, 2009.

In the third quarter of 2009, the increase in the fair value of derivative instruments was primarily due to the impact of decreased forward Alberta power prices on CPLP's portfolio position and the impact of strengthening future prices for the Canadian dollar relative to the U.S. dollar on CPILP's foreign exchange contracts. This was partly offset by a decrease in the fair value of CPILP's natural gas supply contracts for the period before they were designated as hedges for accounting purposes on July 31, 2009.

Quarterly Common Share Trading Information

The Company's common shares trade on the Toronto Stock Exchange under the symbol CPX and began trading on June 26, 2009.

(unaudited)	Three months ended							
	Mar 31, 2011	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009	Sept 30, 2009	June 30, 2009
Share price ($/ common share)								
High	26.44	24.84	24.20	23.39	23.00	21.78	22.39	23.00
Low	22.80	23.25	21.75	21.76	20.97	18.95	19.50	22.00
Close	25.92	23.65	24.10	22.14	22.50	21.37	19.75	22.35
Volume traded (millions)	8.9	3.4	2.4	4.4	7.6	6.5	12.1	5.8

As at April 27, 2011, the Company had 40.418 million common shares outstanding, 47.416 million special voting shares outstanding, 5 million Cumulative Rate Reset Preference Shares, Series 1 outstanding and one special limited voting share outstanding. The weighted average number of common shares outstanding on a diluted basis was 32.320 million for the quarter ended March 31, 2011. All of the outstanding special voting shares and the outstanding special limited voting share are held indirectly by EPCOR.

As at April 27, 2011, CPLP had 21.75 million general partnership units outstanding, 18.524 million common limited partnership units outstanding and 47.416 million exchangeable limited partnership units outstanding, which are exchangeable for 47.416 million common shares of the Company. All of the outstanding general partnership units and the outstanding common limited partnership units are held, indirectly, by the Company. All of the outstanding exchangeable limited partnership units are held indirectly by EPCOR.

As at April 27, 2011, CPILP had 56.3 million limited partnership units outstanding and 16.5 million of such units, representing 29.4% of the outstanding limited partnership units, were held by CPI Investments Inc. EPCOR held 51 Class A Shares of CPI Investments Inc. representing 51% of the votes and CPLP held 49 Class B Shares of CPI Investments Inc. representing 49% of the votes. CPLP had an effective 100% economic interest in CPI Investments Inc.

Additional Information

Additional information relating to Capital Power Corporation, including the Company's annual information form and other continuous disclosure documents, is available on SEDAR at www.sedar.com.

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Income
(Unaudited, in millions of Canadian dollars, except per share amounts)

	Three months ended March 31, 2011	2010 (note 13)
Revenues	$ 440	$ 484
Other income	18	17
Energy purchases and fuel	(291)	(284)
Gross income	167	217
Other raw materials and operating charges	(29)	(19)
Staff costs and employee benefits expense	(39)	(41)
Depreciation and amortization	(58)	(57)
Other administrative expenses	(10)	(10)
Property taxes	(5)	(5)
Foreign exchange losses	(2)	(1)
Operating income	24	84
Gain on sale of power syndicate agreement (note 4)	-	28
Finance expense	(9)	(19)
Income before tax	15	93
Income tax (expense) recovery (note 5)	(1)	(1)
Net income	$ 14	$ 92
Attributable to:		
Non-controlling interests	$ 11	$ 80
Shareholders of the Company	$ 3	$ 12

Earnings per share (all from continuing operations attributable to common shareholders of the company):

	2011	2010
Basic (note 6)	$ 0.06	$ 0.55
Diluted (note 6)	$ 0.05	$ 0.55

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Comprehensive Income (Loss)
(Unaudited, in millions of Canadian dollars)

	Three months ended March 31,	
	2011	2010
Net income	$ 14	$ 92
Other comprehensive loss:		
Available-for-sale assets:		
Unrealized gains on available-for-sale financial assets[1]	-	2
Cash flow hedges:		
Unrealized losses on derivative instruments[2]	(53)	(17)
Reclassification of (gains) losses on derivative instruments to income for the period[3]	(3)	6
Reclassification of ineffective portion to income for the period[4]	1	(1)
Net investment in foreign subsidiaries:		
Unrealized loss[5]	(12)	(19)
Other comprehensive loss, net of tax	(67)	(29)
Total comprehensive (loss) income	$ (53)	$ 63
Attributable to:		
Non-controlling interests	$ (31)	$ 51
Shareholders of the Company	$ (22)	$ 12

[1] For the three months ended March 31, 2011, net of income tax expense of nil. For the three months ended March 31, 2010, net of income tax expense of nil.

[2] For the three months ended March 31, 2011, net of income tax recovery of $6. For the three months ended March 31, 2010, net of income tax recovery of $8.

[3] For the three months ended March 31, 2011, net of reclassification of income tax expense of nil. For the three months ended March 31, 2010, net of reclassification of income tax recovery of $1.

[4] For the three months ended March 31, 2011, net of reclassification of income tax expense of nil. For the three months ended March 31, 2010, net of reclassification of income tax expense of nil.

[5] For the three months ended March 31, 2011, net of income tax expense of $1. For the three months ended March 31, 2010, net of income tax expense of $2.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Financial Position
(Unaudited, in millions of Canadian dollars)

	March 31, 2011	December 31, 2010 (note 13)	January 1, 2010 (note 13)
Assets			
Current assets:			
Cash and cash equivalents	$ 74	$ 56	$ 52
Trade and other receivables	249	286	315
Inventories	56	60	68
Derivative financial instruments assets (note 7)	84	152	146
Assets held for sale (note 4)	-	-	36
	463	554	617
Non-current assets:			
Other assets	20	19	20
Derivative financial instruments assets (note 7)	60	76	155
Finance lease receivables (note 14(a))	83	85	91
Other financial assets	89	89	70
Deferred tax assets	20	40	33
Intangible assets (note 14(b))	630	651	702
Property, plant and equipment (note 14(c))	3,706	3,678	3,345
Goodwill (note 14(d))	103	104	128
Total assets	$ 5,174	$ 5,296	$ 5,161
Liabilities and Equity			
Current liabilities:			
Trade and other payables	$ 246	$ 282	$ 325
Derivative financial instruments liabilities (note 7)	128	125	107
Loans and borrowings	235	235	247
Deferred revenue and other liabilities	10	10	8
Provisions (note 14(e))	19	20	8
	638	672	695
Non-current liabilities:			
Derivative financial instruments liabilities (note 7)	87	89	95
Loans and borrowings	1,446	1,634	1,472
Deferred revenue and other liabilities	66	61	55
Deferred tax liabilities	48	73	92
Provisions (note 14(e))	148	155	136
	1,795	2,012	1,850
Equity:			
Equity attributable to shareholders of the Company			
Share capital (note 8)	1,047	820	477
Retained earnings	5	8	7
Other reserves	(20)	5	9
Retained earnings and other reserves	(15)	13	16
	1,032	833	493
Non-controlling interests	1,709	1,779	2,123
Total equity	2,741	2,612	2,616
Subsequent events (note 12)			
Total liabilities and equity	$ 5,174	$ 5,296	$ 5,161

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

	Share capital (note 8)	Cash flow hedges[1]	Cumulative Translation account[1]	Available-for-sale financial assets[1]	Defined benefit plan actuarial gains and losses[1]	Employee benefits	Retained earnings	Equity attributable to shareholders of the Company	Non-controllin interests	Total
Equity as at January 1, 2011	$ 820	$ 5	$ (5)	$ 1	$ (2)	$ 6	$ 8	$ 833	$ 1,779	$ 2,612
Net income	-	-	-	-	-	-	3	3	11	14
Other comprehensive income:										
Cash flow derivative hedge losses	-	(59)	-	-	-	-	-	(59)	-	(59)
Reclassification of gains to income	-	(3)	-	-	-	-	-	(3)	-	(3)
Reclassification of ineffective portion to income	-	1	-	-	-	-	-	1	-	1
Unrealized gain on foreign currency translation	-	-	(11)	-	-	-	-	(11)	-	(11)
Tax on items recognized directly in equity	-	6	(1)	-	-	-	-	5	-	5
Attributed to non-controlling interest's	-	32	10	-	-	-	-	42	(42)	-
Other comprehensive income	$ -	$ (23)	$ (2)	$ -	$ -	$ -	$ -	$ (25)	$ (42)	$ (67)
Total comprehensive income	-	(23)	(2)	-	-	-	3	(22)	(31)	(53)
Issue of share capital	234	-	-	-	-	-	8	242	(13)	229
Transaction costs	(9)	-	-	-	-	-	-	(9)	-	(9)
Deferred taxes	2	-	-	-	-	-	-	2	-	2
Distributions to non-controlling interests	-	-	-	-	-	-	-	-	(32)	(32)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	-	3	3
Issue of partnership units	-	-	-	-	-	-	-	-	7	7
Common share dividends (note 8)	-	-	-	-	-	-	(12)	(12)	-	(12)
Preferred share dividends (note 8)	-	-	-	-	-	-	(2)	(2)	-	(2)
Preferred share dividends paid by subsidiary company	-	-	-	-	-	-	-	-	(4)	(4)
Equity as at March 31, 2011	$1,047	$ (18)	$ (7)	$ 1	$ (2)	$ 6	$ 5	$ 1,032	$ 1,709	$ 2,741

[1] Accumulated other comprehensive income (loss). Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive income (loss) and the employee benefits reserve.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Changes in Equity
(Unaudited, in millions of Canadian dollars)

	Share capital (note 8)	Cash flow hedges[1]	Cumulative Translation account[1]	Available-for-sale financial assets[1]	Employee benefits	Retained earnings	Equity attributable to shareholders of the Company	Non-controlling interests	Total
Equity as at January 1, 2010	$ 477	$ 7	$ -	$ -	$ 2	$ 7	$ 493	$ 2,123	$ 2,616
Net income	-	-	-	-	-	12	12	80	92
Other comprehensive income:									
Net change in fair value of available-for-sale financial assets	-	-	-	2	-	-	2	-	2
Cash flow derivative hedge losses	-	(25)	-	-	-	-	(25)	-	(25)
Reclassification of losses to income	-	7	-	-	-	-	7	-	7
Reclassification of ineffective portion to income	-	(1)	-	-	-	-	(1)	-	(1)
Unrealized gain on foreign currency translation	-	-	(17)	-	-	-	(17)	-	(17)
Tax on items recognized directly in equity	-	7	(2)	-	-	-	5	-	5
Attributed to non-controlling interest's	-	13	18	(2)	-	-	29	(29)	-
Other comprehensive income	$ -	$ 1	$ (1)	$ -	$ -	$ -	$ -	$ (29)	$ (29)
Total comprehensive income	-	1	(1)	-	-	12	12	51	63
Distributions to non-controlling interests	-	-	-	-	-	-	-	(35)	(35)
Additional investment by non-controlling interests	-	-	-	-	-	-	-	1	1
Issue of partnership units	-	-	-	-	-	-	-	7	7
Common share dividends (note 8)	-	-	-	-	-	(7)	(7)	-	(7)
Preferred share dividends paid by subsidiary company	-	-	-	-	-	-	-	(4)	(4)
Share-based compensation	-	-	-	-	1	-	1	-	1
Equity as at March 31, 2010	$ 477	$ 8	$ (1)	$ -	$ 3	$ 12	$ 499	$ 2,143	$ 2,642

[1] Accumulated other comprehensive income (loss). Other reserves on the statements of financial position are the aggregate of accumulated other comprehensive income (loss) and the employee benefits reserve.

See accompanying notes to the condensed interim consolidated financial statements

CAPITAL POWER CORPORATION

Condensed Interim Consolidated Statements of Cash Flows
(Unaudited, in millions of Canadian dollars)

	Three months ended March 31, 2011	2010
Cash flows from operating activities:		
Net income	$ 14	$ 92
Non-cash adjustments to reconcile net income to net cash flows from operating activities:		
Depreciation and amortization	58	57
Gain on sale of power syndicate agreement (note 4)	-	(28)
Finance expense	9	19
Fair value changes on derivative instruments	24	(7)
Unrealized foreign exchange losses	1	2
Income tax expense	1	1
Other items	15	(4)
Interest paid[1]	(12)	(12)
Income taxes paid	(9)	(2)
Income taxes recovered	-	10
	101	128
Change in non-cash operating working capital	-	(1)
Net cash flows from operating activities	101	127
Cash flows from investing activities:		
Payments to acquire property, plant and equipment and other assets	(89)	(62)
Proceeds on sale of power syndicate agreement (note 4)	-	64
Other cash flows from investing activities	11	3
Net cash flows (used in) from investing activities	(78)	5
Cash flows from financing activities:		
Repayment of long-term debt	(176)	(69)
Proceeds from issue of common shares	234	-
Share issue costs	(9)	-
Distributions paid to non-controlling interests	(25)	(28)
Common share dividends paid (note 8)	(10)	(7)
Preferred share dividends paid (note 8)	(2)	-
Preferred share dividends paid by subsidiary	(4)	(3)
Financing interest paid[1]	(12)	(11)
Net cash flows used in financing activities	(4)	(118)
Foreign exchange losses on cash held in a foreign currency	(1)	(1)
Net increase in cash and cash equivalents	18	13
Cash and cash equivalents at beginning of period	56	52
Cash and cash equivalents at end of period	$ 74	$ 65

[1] Total interest paid.

See accompanying notes to the condensed interim consolidated financial statements

1. Reporting entity:

Capital Power Corporation (the Company or Capital Power) builds, owns and operates power plants and manages its related electricity and natural gas portfolios by undertaking trading and marketing activities.

The registered and head office of the Company is located at 10088-102 Avenue, Edmonton, Alberta, Canada, T5J 2Z1. The common shares of the Company are traded on the Toronto Stock Exchange under the symbol "CPX".

Interim results will fluctuate due to plant maintenance schedules, the seasonal demands for electricity and changes in energy prices. Consequently, interim results are not necessarily indicative of annual results.

2. Significant accounting policies:

(a) Basis of presentation and conversion to IFRS:

These condensed interim consolidated financial statements have been prepared by Management in accordance with International Accounting Standards (IAS) 34, Interim Financial Reporting. These are the Company's first condensed interim consolidated financial statements for part of the period covered by the first International Financial Reporting Standards (IFRS) annual financial statements and IFRS 1 First time Adoption of International Financial Reporting Standards has been applied. The condensed interim consolidated financial statements do not include all of the information required for full annual financial statements.

An explanation of how the transition to IFRS has affected the financial position, financial performance and cash flows of the Company is provided in note 13. This note includes reconciliations of equity and total comprehensive income reported under previous Canadian generally accepted accounting principles (GAAP) to those reported under IFRS for the opening IFRS balance sheet as at January 1, 2010 (transitional date), as at and for the three months ended March 31, 2010 and as at and for the year ended December 31, 2010.

These condensed interim consolidated financial statements have been prepared under the historical cost basis, except for the revaluation of the Company's derivative instruments, cash, equity investments and cash-settled share based payments, which are stated at fair value. In addition, the Company's defined benefit pension assets are recognized at fair value.

These condensed interim consolidated financial statements were approved and authorized for issue by the Board of Directors on April 28, 2011. These condensed interim consolidated financial statements should be read in conjunction with the Company's 2010 annual financial statements prepared in accordance with Canadian GAAP and in consideration of the IFRS transition disclosures included in note 13 to these financial statements and the additional annual comparative disclosures included herein.

(b) Basis of consolidation:

These condensed interim consolidated financial statements include the accounts of Capital Power and its subsidiaries. Subsidiaries are fully consolidated from the date of acquisition, being the date on which the Company obtains control, and continue to be consolidated until the date that such control ceases to exist.

The Company has an approximate 29.4% interest in Capital Power Income L.P. (CPILP) (December 31, 2010 – 29.6%, January 1, 2010 – 30.5%) and an approximate 45.9% interest in Capital Power LP (CPLP) (December 31, 2010 – 39.5%, January 1, 2010 – 27.8%). Based on an assessment of the relationship between Capital Power and these entities, they are treated as subsidiaries of Capital Power.

2. Significant accounting policies, continued:

(b) Basis of consolidation, continued:

EPCOR Utilities Inc. (EPCOR) holds 47.416 million (December 31, 2010 – 47.416 million, January 1, 2010 – 56.625 million) exchangeable limited partnership units of CPLP (exchangeable for common shares of Capital Power on a one-for-one basis) which represents approximately 54.1% of CPLP (December 31, 2010 – 60.5%, January 1, 2010 – 72.2%). Each exchangeable limited partnership unit is accompanied by a special voting share in the capital of Capital Power which entitles the holder to a vote at Capital Power shareholder meetings, subject to the restriction that such special voting shares must at all times represent not more than 49% of the votes attached to all Capital Power common shares and special voting shares, taken together. The special voting shares also entitle EPCOR, voting separately as a class, to nominate and elect a maximum of four directors of Capital Power of the current twelve directors on Capital Power's board of directors. Although EPCOR is the largest single shareholder, its representation on the board of directors does not represent a controlling vote. Since a subsidiary of Capital Power, is the general partner of CPLP, Capital Power has control over CPLP and, on that basis, the operations of CPLP are consolidated by Capital Power for financial statement purposes.

CPLP holds 49% and EPCOR holds 51% of the voting rights in CPI Investments Inc. CPI Investments Inc. owns the approximate 29.4% interest (December 31, 2010 – 29.6%, January 1, 2010 – 30.5%) in CPILP previously owned by EPCOR. However, CPLP is entitled to all of the economic interest in CPI Investments Inc. Under IFRS, CPLP is the primary beneficiary of CPI Investments Inc. and accordingly, CPLP, and therefore CPC, consolidates the financial results of CPILP.

Non-controlling interests in subsidiaries are identified separately from the Company’s equity. The non-controlling interests may be initially measured either at fair value or at the non-controlling interests’ proportionate share of the fair value of the acquired business’ identifiable net assets. The choice of measurement basis is made on an acquisition-by-acquisition basis. Subsequent to acquisition, the carrying amount of non-controlling interests is the amount of those interests at initial recognition plus the non-controlling interest’s share of subsequent changes in equity. Total comprehensive income is attributed to non-controlling interests even if this results in the non-controlling interests having a deficit balance.

All significant intercompany balances and transactions have been eliminated on consolidation.

The financial statements of the subsidiaries are prepared for the same reporting period as Capital Power, using consistent accounting policies.

(c) Business combinations and goodwill:

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The consideration of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of acquisition in exchange for control of the acquired business. Acquisition-related costs are recognized into net income as incurred. Goodwill is measured as the excess of the fair value of the consideration transferred less the fair value of the identifiable assets acquired and liabilities assumed. When the excess is negative, a bargain purchase gain is recognized immediately into income.

Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the date of acquisition. Where an acquisition involves consideration contingent on future events, any changes in the amount of consideration paid will be recognized into net income.

2. Significant accounting policies, continued:

(c) Business combinations and goodwill, continued:

The Company elects on a transaction-by-transaction basis whether to measure non-controlling interest at its fair value, or at its proportionate share of the recognized amount of the identifiable net assets, at the acquisition date. Transaction costs, other than those associated with the issue of debt or equity securities, that the Company incurs in connection with a business combination are expensed as incurred.

Acquisitions prior to January 1, 2010

On transition to IFRS, the Company has elected not to restate business combinations that occurred prior to the date of transition, January 1, 2010, as discussed in note 13. Any goodwill arising on such business combinations before the date of transition represents the amount recognized under previous Canadian GAAP.

Goodwill

After initial recognition, goodwill is not amortized, but is measured at cost less any accumulated impairment losses. Goodwill is tested for impairment annually at the cash-generating unit (CGU) level. For the purpose of impairment testing, goodwill acquired in an acquisition is, from the date of acquisition, allocated to each of the Company's CGUs that are expected to benefit from the acquisition. For further discussion over impairment of goodwill, refer to the accounting policy for impairment of non-financial assets.

Where goodwill forms part of a CGU and part of the operation within that unit is disposed of, the goodwill associated with the operation disposed of is included in the carrying amount of the operation when determining the gain or loss on disposal of the operation. Goodwill disposed of in this circumstance is measured based on the relative values of the operation disposed of and the portion of the CGU retained.

(d) Investments in joint ventures:

Capital Power has interests with other parties, whereby in each case the venturers have a contractual arrangement that establishes joint control over the economic activities of the arrangement. These arrangements involve the joint ownership of assets which are used to obtain benefits for each venturer, and are considered to be joint asset arrangements.

In these situations Capital Power recognizes its share of the jointly controlled assets and liabilities in accordance with those associated rights and obligations, along with its share of the income from the output of the jointly controlled asset along with its share of any expenses incurred by the joint arrangement.

(e) Foreign currency translation:

Transactions in foreign currencies are translated to the respective functional currencies of the Company, or the subsidiary concerned, at exchange rates in effect at the transaction date. At each reporting date monetary assets and liabilities denominated in foreign currencies are translated at the exchange rate in effect at the date of the statement of financial position. Other non-monetary assets are not retranslated unless they are carried at fair value. Revenues and expenses are translated at average exchange rates prevailing during the period. The resulting foreign exchange gains and losses are included in net income.

On consolidation the assets and liabilities of operations that have a functional currency that is different from the Company's functional currency of Canadian dollars, principally on U.S. operations that have a functional currency of U.S. dollars, are translated into Canadian dollars at the exchange rates in effect at the date of the statement of financial position. Revenues and expenses are translated at average exchange rates prevailing during the period. The resulting translation gains and losses are deferred and included in accumulated other comprehensive income as part of translation gains and losses.

2. Significant accounting policies, continued:

(f) Revenue recognition:

Energy sales

Revenues from the sales of electricity and natural gas are recognized when the risks and rewards of ownership pass to the buyer, collection is reasonably assured and the price is reasonably determinable. This occurs upon delivery or availability for delivery under take-or-pay contracts. These revenues include an estimate of the value of electricity and natural gas consumed by customers, but billed subsequent to period-end.

The Company recognizes revenues from certain of its generation units operating under power purchase agreements (PPAs) as described in note 2(g). PPAs are a form of long-term sales arrangement between the owner of a generation unit and the buyer of the PPA.

Revenues from other generation units operating under PPAs, which have not been assessed as containing a lease are recognized on delivery of output or upon availability for delivery as prescribed by the respective PPA. In determining the fair value of revenue to be recognized for certain long-term contracts which contain fixed rates which vary dependent on cumulative volume delivered, revenue is recognized as the lower of (1) the megawatt hours (MWhs) made available during the period multiplied by the billable contract price per MWh and (2) an amount determined by the MWhs made available during the period, multiplied by the average price per MWh over the term of the contract from the date of acquisition. Any excess of the contract price over the average price is recorded as deferred revenue.

Revenues from the sale of other goods are recognized when the products have been delivered.

Service revenues

Revenues from operating and management services are recognized when the service has been performed or delivered.

Derivative instruments

Revenues also include realized and unrealized gains and losses from derivatives used in the risk management of the Company's generation activities related to commodity prices and foreign currency risk, and from the Company's proprietary trading activities. Realized gains and losses are recognized when the settlement of short positions occurs and unrealized gains and losses are recorded as revenues based on the related changes in the fair value of the financial instrument at the end of each reporting period.

Deferred revenues

Payments received on one of the Company’s operating leases may be in excess of accounting lease revenues. In such cases, the Company records deferred revenues and other liabilities on its consolidated statement of financial position.

Monetary contributions received from third parties used to either connect a customer to a network or to provide the customer with ongoing access to a supply of goods or services are measured at fair value of the cash received and are initially recorded as deferred revenue. Revenue is recognized as the service is performed, or if an ongoing service is performed as part of an agreement, over the life of the agreement but no longer than the life of the asset.

(g) Leases or arrangements containing a lease:

The Company has entered into PPAs to sell power at predetermined prices. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the Company's property, plant and equipment in return for payment. Such types of arrangements may be classified as either finance or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property from the Company are classified as finance leases. PPAs that do not transfer all of the benefits and risks of ownership of property, plant and equipment are classified as either operating leases or executory contracts.

2. Significant accounting policies, continued:

(g) Leases or arrangements containing a lease, continued:

For those PPAs determined to be finance leases with the Company as the lessor, finance income related to leases or arrangements accounted for as finance leases is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is composed of minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying amount of the leased property. Unearned finance income is deferred and recognized into net income over the lease term.

Payments received under PPAs classified as finance leases are segmented into those for the lease and those for other elements on the basis of their relative fair value.

For those PPAs determined to be operating leases with the Company as the lessor, revenue is recognized on a straight line basis unless another method better represents the earning process.

Where the Company has purchased goods or services as a lessee, and the lease has been determined to be an operating lease, rental payments are expensed on a straight line basis over the life of the lease. The Company has not entered into any finance lease arrangements as a lessee.

(h) Non-derivative financial instruments:

Financial assets are identified and classified as either available for sale, held at fair value through income or loss, or loans and receivables. Financial liabilities are classified as either held at fair value through income or loss or other financial liabilities.

Financial instruments at fair value through income or loss

A financial asset is classified as held at fair value through income or loss if it is classified as held for trading or is designated as such upon initial recognition. The Company may designate financial instruments as held at fair value through income or loss when such financial instruments have a reliably determinable fair value and where doing so eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets and liabilities or recognizing gains and losses on them on a different basis.

Upon initial recognition transaction costs are recognized into net income as incurred. Financial assets classified as held at fair value through income or loss are measured at fair value with the changes in fair value reported in net income.

Gains or losses realized on de-recognition of investments held at fair value through income or loss are recognized into net income.

Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. The Company's current loans and receivables comprise its cash and cash equivalents and trade and other receivables. Non-current loans and other long-term receivables comprise promissory notes receivable and amounts due from customers more than one year from the date of the statement of financial position which will be repaid between 2011 and 2025.

These assets are recognized initially at fair value plus any directly attributable transaction costs. After initial recognition they are measured at amortized cost using the effective interest method less any impairment losses as described in note 2(o). The effective interest method calculates the amortized cost of a financial asset or liability and allocates the interest income or expense over the term of the financial asset or liability using an effective interest rate.

2. Significant accounting policies, continued:

(h) Non-derivative financial instruments, continued:

Available-for-sale financial assets

The Company's equity investments are classified as available-for-sale financial assets. Available-for-sale financial assets are measured at fair value with any changes in fair value reported in other comprehensive income until the asset is disposed of, or becomes impaired, as described in note 2(o). On derecognition of an available-for-sale financial asset the cumulative gain or loss that was previously recognized in equity is transferred to net income.

Other financial liabilities

The Company's loans and borrowings and trade and other payables are recognized on the date at which the Company becomes a party to the contractual arrangement. Liabilities are derecognized when the contractual obligations are discharged or cancelled or expire.

Liabilities are recognized initially at fair value plus any directly attributable transaction costs, such as debenture discounts, premiums and issue expenses. Subsequently these liabilities are measured at amortized cost using the effective interest rate method.

Financial assets and financial liabilities are presented on a net basis when the Company has a legally enforceable right to set-off the recognized amounts and intends to settle on a net basis or to realize the asset and settle the liability simultaneously.

(i) Derivative instruments and hedging activities:

To reduce its exposure to movements in energy commodity prices, interest rate changes, and foreign currency exchange rates, the Company uses various risk management techniques including the use of derivative instruments. Derivative instruments may include forward contracts, fixed-for-floating swaps, and option contracts. Such instruments may be used to establish a fixed price for an energy commodity, an interest-bearing obligation or an obligation denominated in a foreign currency.

All derivative instruments, including embedded derivatives, are recorded at fair value on the statement of financial position as derivative instrument assets or derivative instrument liabilities except for embedded derivative instruments that are clearly and closely related to their host contract and the combined instrument is not measured at fair value. Any contract to buy or sell a non-financial item is not treated as a non-financial derivative if that contract was entered into and continues to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the Company's expected purchase, sale or usage requirements. The Company accounts separately for any embedded derivatives in any hybrid instruments issued or acquired. The Company does not account for foreign currency derivatives embedded in non-financial instrument host contracts when the currency that is commonly used in contracts to purchase or sell non-financial items in the economic environment is that currency in which the transaction takes place.

All changes in the fair value of derivatives are recorded in net income unless cash flow hedge accounting is used, in which case changes in the fair value of the effective portion of the derivatives are recorded in other comprehensive income.

The Company uses financial contracts-for-differences (or fixed-for-floating swaps) to hedge the Company's exposure to fluctuations in electricity prices. Under these instruments, the Company agrees to exchange, with creditworthy or adequately secured counterparties, the difference between the variable or indexed price and the fixed price on a notional quantity of the underlying commodity for a specified timeframe.

2. Significant accounting policies, continued:

(i) Derivative instruments and hedging activities, continued:

The Company uses non-financial forward delivery derivatives to manage the Company's exposure to fluctuations in natural gas prices related to its natural gas customer contracts and obligations arising from its natural gas fired generation facilities. Under these instruments, the Company agrees to sell or purchase natural gas at a fixed price for delivery of a pre-determined quantity under a specified timeframe.

Foreign exchange forward contracts are used by the Company to manage foreign exchange exposures, consisting mainly of U.S. dollar exposures, resulting from anticipated transactions denominated in foreign currencies. For transactions involving the development or acquisition of property, plant and equipment, when the real or anticipated transaction subsequently results in the recognition of a financial asset, the associated gains or losses on derivative instruments are included in the initial carrying amount of the asset acquired in the same period or periods in which the asset is acquired or constructed.

The Company may use non-financial or financial commodity derivative trades which are transacted with the intent of benefiting from short-term actual or expected differences between their buying and selling prices or to lock in arbitrage opportunities. Such trades are recognized on a net basis in the Company's revenues.

The Company may use hedge accounting when there is a high degree of correlation between the risk in the item designated as being hedged (the hedged item) and the derivative instrument designated as a hedge (the hedging instrument). The Company documents all relationships between hedging instruments and hedged items at the hedge's inception, including its risk management objectives and its assessment of the effectiveness of the hedging relationship on a retrospective and prospective basis.

The Company uses cash flow hedges for certain of its anticipated transactions to reduce exposure to fluctuations in changes in commodity prices. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income, while the ineffective portion is recognized in energy revenues or energy purchases or fuel, as appropriate. The amounts recognized in the other comprehensive income as cash flow hedging gains/losses are reclassified into net income in the same period or periods in which the hedged item occurs and is recorded in net income when it becomes probable that the hedged items will not occur.

The Company has not designated any fair value hedges at the date of the statement of financial position.

A hedging relationship is discontinued if the hedge relationship ceases to be effective, if the hedged item is an anticipated transaction and it is probable that the transaction will not occur by the end of the originally specified time period, if the Company terminates its designation of the hedging relationship, or if either the hedged or hedging instrument ceases to exist as a result of its maturity, expiry, sale, termination or cancellation and is not replaced as part of the Company's hedging strategy.

If a cash flow hedging relationship is discontinued or ceases to be effective, any cumulative gains or losses arising prior to such time are deferred in accumulated other comprehensive income as part of cash flow hedging gains/losses and recognized in net income in the same period as the hedged item, and subsequent changes in the fair value of the derivative instrument are reflected in net income. If the hedged or hedging item matures, expires, or is sold, extinguished or terminated and the hedging item is not replaced, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the same period as the corresponding gains or losses on the hedged item. When it is no longer probable that an anticipated transaction will occur within the originally determined period and the associated cash flow hedge has been discontinued, any gains or losses associated with the hedging item that were previously recognized in other comprehensive income are recognized in net income in the period.

2. Significant accounting policies, continued:

(i) Derivative instruments and hedging activities, continued:

When the conditions for hedge accounting cannot be applied, the changes in fair value of the derivative instruments are recognized in net income. The fair value of derivative financial instruments reflects changes in the commodity market prices, interest rates and foreign exchange rates. Fair value is determined based on exchange or over-the-counter quotations by reference to bid or asking price, as appropriate, in active markets. In illiquid or inactive markets, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates using external readily observable market data such as future prices, interest rate yield curves, foreign exchange rates, discount rates for time value, and volatility where available. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

(j) Property, plant and equipment:

Property, plant and equipment are recorded at cost, net of accumulated depreciation and/or accumulated impairment losses, if any.

Capitalization

Cost includes contracted services, materials, borrowing costs on qualifying assets, direct labour, directly attributable overhead costs, development costs associated with specific property, plant and equipment and asset retirement costs. When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

The cost of replacing a part of an item of property, plant and equipment is capitalized if it is probable that the future economic benefits of the part will flow to the Company and that its cost can be measured reliably. The carrying amount of the replaced part is derecognized. Costs of day to day repairs and maintenance costs are recognized into net income as incurred.

Depreciation

Depreciation is charged to net income on a straight line basis over the estimated useful lives of each part of an item of property, plant and equipment, since this most closely reflects the expected pattern of consumption of the asset. Major components of property, plant and equipment are depreciated separately over their respective useful lives. Land and construction work in progress are not depreciated. The estimated useful lives for generation plants and equipment range from 1 to 60 years.

The estimated useful lives, residual values and methods of depreciation are reviewed annually, and adjusted prospectively if appropriate.

Gains and losses on the disposal or retirement of an item of property, plant and equipment are determined as the difference between the net disposal proceeds and the carrying amount at the date of disposal. The gains or losses are recognized into net income within other operating income or other operating costs.

2. Significant accounting policies, continued:

(k) Intangible assets:

Capitalization

Intangible assets with definite lives are stated at cost, net of accumulated amortization and any accumulated impairment losses. Intangible assets with definite lives are amortized over the related assets useful lives, as described below. Refer to note 14(b) for additional discussion over intangible assets.

The only indefinite life intangible assets recorded by the Company are the emission credits.

Amortization

Amortization is charged to net income on a straight line basis to write-off the cost less the estimated residual value over the estimated remaining term of the agreement or in line with the life of the related generating plant to which it relates. Software work in progress is not amortized as the software is not available for use. Land lease rights will be amortized when the related wind power assets are constructed and commissioned for service over the lives of the related wind power plants. Coal supply access rights will be amortized when the Keephills 3 plant is commissioned for service over the life of the coal supply agreement. Emission credits are not amortized, but are expensed as the associated benefits are realized. The periods over which intangible assets are amortized are as follows:

Alberta PPAs	11 years
CPILP PPAs	over the terms of the contracts
Contract rights	15 to 31 years
Water rights	over the lives of the associated property, plant and equipment
Software	1 to 10 years
Customer rights	30 years

Estimated useful lives, methods of amortization and residual values are reviewed annually, and adjusted prospectively if required.

Gains or losses on the disposal of intangible assets are determined as the difference between the net disposal proceeds and the carrying amount of the asset, and are recognized into net income as other operating income or other operating costs.

(l) Research and development costs:

Expenditures on research activities, undertaken with the prospect of gaining new scientific or technical knowledge and understanding, are recognized in income or loss as incurred.

Development activities involve a plan or design for the production of new or substantially improved products and processes. Development expenditures are capitalized only if development costs can be measured reliably, the product or process is technically and commercially feasible, future economic benefits are probable, and the Company intends to and has sufficient resources to complete development and to use or sell the asset. Other development expenditures are recognized in income or loss as incurred.

Capitalized development expenditures are measured at cost less accumulated amortization and accumulated impairment losses.

(m) Capitalized borrowing costs:

The Company capitalizes interest during construction on its property, plant and equipment and intangible assets to provide for the costs of borrowing on its construction activities. Where project specific debt is not used to finance construction, interest is applied during construction using the weighted average cost of debt incurred on the Company's external borrowings used to finance qualifying assets. Qualifying assets are those which necessarily take a significant amount of time to get ready for their intended use.

2. Significant accounting policies, continued:

(n) Impairment of non-financial assets:

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into a CGU, which is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. For the purposes of goodwill impairment testing, goodwill acquired in a business combination is allocated to the CGU, or the group of CGUs, that is expected to benefit from the synergies of the combination. This allocation is subject to an operating segment ceiling test and reflects the lowest level at which that goodwill is monitored for internal reporting purposes.

The Company reviews the recoverability of non-financial assets subject to depreciation or amortization (property, plant and equipment and definite life intangible assets) when events or changes in circumstances may indicate or cause the asset's carrying amount to exceed its recoverable amount. The Company reviews the recoverability of goodwill and indefinite life intangibles on an annual basis. The asset's recoverable amount is the higher of its fair value less cost to sell and its value in use. The value in use is the present value of expected future cash flows discounted using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. Fair value less cost to sell is based on estimated market values based on actual market transactions, if available. When actual market transactions are not available, a valuation model is used.

The Company's corporate assets do not generate separate cash inflows. If there is an indication that a corporate asset may be impaired, then the recoverable amount is determined for the CGU to which the corporate asset belongs.

Any impairment loss would be recorded in net income in the period when it is determined that the carrying amount of the asset may not be recoverable. The impairment loss would be recorded as the excess of the carrying amount of the asset over its recoverable amount. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs, and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

At the end of each reporting period the Company makes an assessment as to whether there is any indication that previously incurred impairment losses no longer exist. If such an indication exists, the Company estimates the asset's recoverable amount. Any reversal is limited so that the carrying amount of the asset does not exceed its recoverable amount or the carrying amount that would have been determined, after depreciation or amortization, had the original impairment loss not been recognized.

Any reversal is recognized into net income for the period. An impairment loss in respect of goodwill is not reversed.

(o) Impairment of financial assets:

Financial assets, other than those classified as held at fair value through income or loss with changes in fair value recognized in the statement of income, are assessed for indicators of impairment at the end of each reporting period. An impairment loss would be recorded for investments recorded at cost where it is identified that there is objective evidence that one or more events has occurred after the initial recognition of the asset, that has had an impact on the estimated future cash flows of the asset that can be reliably estimated.

For listed and unlisted equity investments classified as available for sale, a significant or prolonged decline in the fair value of the investment below its cost is considered to be objective evidence of impairment.

2. Significant accounting policies, continued:

(o) Impairment of financial assets, continued:

For certain categories of financial assets, such as trade receivables, assets that are assessed not to be impaired individually are in addition assessed for impairment on a collective basis. Objective evidence of impairment includes the Company's past experience of collecting payments, as well as observable changes in national or local economic conditions.

For financial assets carried at amortized cost, the amount of the impairment loss recognized is the difference between the asset's carrying amount and the present value of estimated future cash flows, discounted at the asset's original effective interest rate. Any impairment loss is recognized in net income. If, in a subsequent reporting period, the amount of the estimated impairment loss increases or decreases because of an event occurring after the impairment was recognized, the previously recognized impairment loss is adjusted through net income.

When an available-for-sale financial asset is considered to be impaired, any cumulative gains or losses previously recognized in other comprehensive income are reclassified to income or loss in the period. Impairment losses previously recognized in income are not reversed through income or loss. Any increase in fair value subsequent to an impairment loss is recognized in other comprehensive income.

(p) Income taxes:

The Company's Canadian subsidiaries are subject to income taxes pursuant to the Income Tax Act (Canada) (ITA) and provincial income tax acts. The Company's U.S. subsidiaries are subject to income tax pursuant to U.S. federal and state tax laws.

The Company follows the asset and liability method of accounting for income taxes. Under this method, current income taxes for the current or prior periods are recognized and measured at the amount expected to be recovered from or payable to the taxation authorities based on the tax rates that are enacted or substantively enacted by the end of the reporting period.

Deferred income tax assets and liabilities are recognized for the deferred tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases.

Deferred tax assets are generally recognized for all deductible temporary differences to the extent that it is probable that taxable income will be available against which those deductible temporary differences can be utilized. Such deferred tax assets and liabilities are not recognized if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable income nor the accounting income.

Deferred tax liabilities are recognized for taxable temporary differences associated with investments in subsidiaries, and interests in joint arrangements, except where the Company is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future. Deferred tax assets arising from deductible temporary differences associated with such investments and interests are only recognized to the extent that it is probable that there will be sufficient taxable income against which to utilize the benefits of the temporary differences and they are expected to reverse in the foreseeable future.

Deferred income tax assets and liabilities are measured using enacted or substantively enacted rates of tax expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled.

The effect of a change in tax rates on deferred tax assets and liabilities is recognized in net income in the period that includes the date of enactment or substantive enactment.

Current and deferred tax relating to items recognized directly in equity is recognized in equity and not in net income.

2. Significant accounting policies, continued:

(q) Inventories:

Parts and other consumables and coal, the majority of which are consumed by the Company in the provision of its goods and services, are valued at the lower of cost and net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of any assembled inventory includes direct labour, materials and directly attributable overhead. The costs of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs. Natural gas inventory held in storage for trading purposes is recorded at fair value less cost to sell, as measured by the one-month forward price of natural gas. Previous write-downs of inventories from cost to net realizable value can be fully or partially reversed if supported by economic circumstance.

(r) Cash and cash equivalents:

Cash and cash equivalents include cash or highly liquid investment-grade short-term investments with original terms to maturity of three months or less, and are measured at amortized cost using the effective interest method.

(s) Government assistance:

Government assistance is recognized when there is reasonable assurance that the Company will comply with the conditions attached to the government assistance and the grants will be received. Such assistance is recorded as a reduction to the related expense or asset.

(t) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. The obligation is discounted using a discount rate that reflects current market assessments of the time value of money and the risks specific to the obligation for which the estimates of future cash flows have not been adjusted. The change in discount rate due to the passage of time is recognized as a finance expense, and is recorded over the estimated time period until settlement of the obligation. Provisions are reviewed and adjusted, when required, to reflect the current best estimate at the end of each reporting period.

The Company recognizes decommissioning provisions in the period in which a legal or constructive obligation is incurred. A corresponding decommissioning cost is added to the carrying amount of the associated property, plant and equipment, and it is depreciated over the estimated useful life of the asset. Accretion of the liability is recorded in finance expense.

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under contract. The provision is measured at the present value of the lower of expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on the assets associated with that contract.

(u) Employee benefits:

The employees of the Company are either members of the Local Authorities Pension Plan (LAPP) or other defined contribution or benefit plans.

The LAPP is a multiemployer defined benefit pension plan. The Trustee of the plan is the Treasurer of Alberta and the plan is administered by a Board of Trustees. The Company and its employees make contributions to the plan at rates prescribed by the Board of Trustees to cover costs under the plan. It is accounted for as a defined contribution plan as insufficient information exists to enable the Company to account for the plan as a defined benefit plan. Accordingly the Company does not recognize its share of any plan surplus or benefit.

2. Significant accounting policies, continued:

(u) Employee benefits, continued:

The Company maintains additional defined contribution and defined benefit pension plans to provide pension benefits to those employees (comprising less than 45% of total employees of Capital Power) who are not otherwise served by LAPP.

The Company accrues its obligations for its defined benefit pension plans net of plan assets. The cost of pension benefits earned by employees is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of expected plan investment performance, salary escalation and retirement ages of employees. For the purpose of calculating the expected return on plan assets, those assets are valued at quoted market value. The discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the date of the statement of financial position on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Past service costs from plan amendments are amortized on a straight-line basis over the estimated average remaining service of employees active at the date of amendment. Actuarial gains or losses on the accrued benefit obligation arise from differences between actual and expected experience and from changes in the actuarial assumptions used to determine the accrued benefit obligation. The Company recognizes all actuarial gains and losses immediately in other comprehensive income.

The Company has an unfunded long-term disability plan which provides provincial health care premiums, health and dental benefits, and required pension contributions for current disabled employees. The plan is a defined benefit plan and the obligation related to long-term disability benefits is actuarially determined using the projected benefit method pro-rated on services and management's best estimate of future health care costs, salary escalation for estimating future benefit contributions, recovery and termination experience, and inflation rates. The discount rate used to calculate the interest cost on the accrued benefit obligation is determined by reference to market interest rates at the date of the statement of financial position on high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Actuarial gains or losses on the accrued benefit obligation arise from differences between actual and expected experience and from changes in the actuarial assumptions used to determine the accrued benefit obligation. Actuarial gains and losses are recognized in net income immediately.

(v) Share-based payments:

The Company operates an equity-settled, share-based compensation plan where each option converts into one common share. The fair value of the employee services received in exchange for the grant of the options is recognized as a compensation expense within staff costs and credited to the employee benefits reserve. The employee benefits reserve is reduced as the options are exercised and the amount initially recorded as a credit in employee benefits reserve is reclassified to share capital. The total amount to be expensed over the vesting period is determined by reference to the fair value of the options granted.

The Company determines the fair value of stock options using a binomial option pricing model at the date of grant. Measurement inputs include the share price on the measurement date, the exercise price of the instrument, expected volatility, expected term of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

The Company has incorporated an estimated forfeiture rate for stock options that will not vest into its determination of share-based compensation for each period.

2. Significant accounting policies, continued:

(v) Share-based payments, continued:

The fair values of the amounts payable to employees/directors in respect of the Performance Share Unit (PSU) Plan and the Directors' Deferred Share Unit (DSU) Plan, which are settled in cash, are recognized as expenses with corresponding increases in liabilities, over the period that the employees/directors unconditionally become entitled to payments. The liability is re-measured at each reporting date to fair value and at settlement date. Any changes in the fair value of the liability are recognized in income or loss.

(w) Earnings per share:

Basic earnings per share is calculated by dividing income available to common shareholders by the weighted average number of common shares outstanding during the period.

Diluted earnings per share is calculated on the treasury stock method, by dividing income available to common shareholders, adjusted for the effects of dilutive securities, by the weighted average number of common shares outstanding during the period and all additional common shares that would have been outstanding had all potential dilutive common shares been issued.

(x) Assets held for sale:

Non-current assets, or disposal groups comprising assets and liabilities, that are expected to be recovered through sale rather than through continuing use, are classified as held for sale. Immediately before classification as held for sale, the assets, or components of the disposal group, are re-measured in accordance with the Company's accounting polices. Thereafter, the assets, or disposal group, are measured at the lower of their carrying amount and fair value less cost to sell. Any impairment losses on initial classification as held for sale or subsequent gain on re-measurement are recognized into net income. Gains are not recognized in excess of any cumulative impairment losses.

(y) Future accounting changes:

A number of new standards, and amendments to standards and interpretations, are not yet effective for the quarter ended March 31, 2011, and have not been applied in preparing these unaudited condensed interim consolidated financial statements. The following standards and interpretations have been issued by the International Accounting Standards Board and the International Financial Reporting Interpretations Committees with effective dates relating to the annual accounting periods starting on or after the effective dates as follows:

	Effective Date
International Accounting Standards (IAS/IFRS)	
IFRS 9 - Financial Instruments	January 1, 2013
IAS 12 – Income taxes	January 1, 2012

The extent of the impact of adoption of these standards and interpretations on the consolidated financial statements of the Company has not been determined.

3. Use of judgments and estimates:

The preparation of the Company's condensed interim consolidated financial statements in accordance with IFRS requires management to make estimates, judgments, and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses in the condensed interim consolidated financial statements and the disclosure of contingent assets and liabilities at the date of the condensed interim consolidated financial statements. The Company reviews its estimates and assumptions on an ongoing basis and uses the most current information available and exercises careful judgment in making these estimates and assumptions.

3. Use of judgments and estimates, continued:

The main assumptions and estimates that were used in preparing the Company's condensed interim consolidated financial statements relate to:

Financial instruments

The valuation of the Company's derivative instruments and certain other financial instruments requires estimation of the fair value of each instrument at the reporting date. Details of the basis on which fair values are estimated are provided in note 7.

Impairments

The recoverable amount of goodwill, intangible assets and property, plant and equipment is based on estimates and assumptions regarding the expected market outlook and cash flows from each CGU. Details of the key estimates used in assessing the recoverable amount of each CGU at the last impairment review date are provided in note 14(d).

Decommissioning and other provisions

Measurement of the Company's provisions and the related change in discount rate require the use of estimates with respect to the amount and timing of asset retirements, the extent of site remediation required and related future cash flows for the decommissioning provisions and estimates of expected customer renewals for the Company's other provisions. The key assumptions used in determining these provisions are provided in note 14(e).

Deferred taxes

Income taxes are determined based on estimates of the Company's current income taxes and estimates of deferred income taxes resulting from temporary tax differences. Deferred income tax assets are assessed to determine the likelihood that they will be realized from future taxable income.

Revenue recognition

As noted in note 2(f), estimates of the value of electricity and natural gas consumed by customers but not billed until subsequent to period-end are based on volume data provided by the parties responsible for delivering the commodity and contracted prices.

Actual results may differ from these estimates. Adjustments to previous estimates, which may be material, will be recorded in the period they become known.

As well as relying on estimates, the Company also makes judgments in applying IFRS to certain activities and transactions. Significant areas where the Company has exercised judgments include:

Classification of arrangements which contain a lease

As noted in note 2(g), the Company has exercised judgment in determining whether the risks and rewards of its generation assets which are subject to a PPA are transferred to the PPA buyer, in determining whether a lease exists and if so, whether the lease should be treated as a finance or operating lease. Details of those PPAs which contain either operating or finance leases are provided in notes 10 and 14(a).

4. Gain on sale of power syndicate:

The Company's interest in the Battle River PSA was disposed of on January 15, 2010 for proceeds of $64 million. The Company recorded an asset held for sale of $36 million as at December 31, 2009 and recognized a gain on disposal of $28 million in the first quarter of 2010. The Battle River PSA was previously acquired by the Company, effective July 1, 2009, as a part of the acquisition of assets from EPCOR Utilities Inc. At the acquisition date, the Company recognized fair value adjustments to the Battle River PSA asset for the Company's then 27.75% share of the Battle River PSA gain on disposal. As a result, the impact on net income attributable to shareholders of the sale of the Battle River PSA in the three months ended March 31, 2010 was nil.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

5. Income tax:

	Three months ended March 31, 2011	2010
Current income tax		
Current income tax	$ 4	$ 14
Deferred income tax		
Relating to origination and reversal of temporary differences	(2)	(7)
Relating to changes in tax rates / new taxes	(2)	(7)
Relating to write-downs of deferred tax asset	1	1
	$ 1	$ 1

	Three months ended March 31, 2011	2010
Income before tax	$ 15	$ 93
Income tax at the statutory rates of 26.5% and 28.0%, respectively	4	26
Increase (decrease) resulting from		
Taxable income attributable to non-controlling interests	(2)	(20)
Change in valuation allowance	1	1
Non-taxable amounts	(1)	(1)
Adjustment for enacted changes in income tax laws and rates	(2)	(7)
Other	1	2
	$ 1	$ 1

6. Earnings per share:

Basic earnings per share

The earnings and weighted average number of common shares used in the calculation of basic earnings per share are as follows:

	Three months ended March 31, 2011	2010
Income for the period attributable to shareholders of the Company	$ 3	$ 12
Preferred share dividends of the Company [1]	(1)	-
Earnings used in the calculation of basic earnings per share	$ 2	$ 12

[1] Includes preferred share dividends in respect of the current quarter only.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

6. Earnings per share, continued:

Basic earnings per share, continued

	Three months ended March 31, 2011	2010
Weighted average number of common shares used in the calculation of basic earnings per share	32,319,690	21,750,000

Diluted earnings per share

The earnings used in the calculation of diluted earnings per share are as follows:

	Three months ended March 31, 2011	2010
Earnings used in the calculation of basic earnings per share	$ 2	$ 12
Effect of exchangeable limited partnership units issued to EPCOR for common shares [1]	2	-
Earnings used in the calculation of diluted earnings per share	$ 4	$ 12

[1] The exchangeable limited partnership units issued to EPCOR may be exchanged for common shares of Capital Power on a one-for-one basis. For the three months ended March 31, 2011, the potential exchange of such units for common shares of the Company had a dilutive impact as the potential exchange would remove the attribution of net income to non-controlling interests related to CPLP of $4 million. Additionally, the income tax provision of the Company would need to be adjusted to reflect the non-controlling interest's share of CPLP income taxes of $2 million. For the three months ended March 31, 2010 the potential exchange of such units for common shares of the Company were not included in the calculation of diluted earnings per share as they were anti-dilutive.

The weighted average number of common shares for the purposes of diluted earnings per share reconciles to the weighted average number of common shares used in the calculation of basic earnings per share as follows:

	Three months ended March 31, 2011	2010
Weighted average number of common shares used in the calculation of basic earnings per share	32,319,690	21,750,000
Effect of dilutive share purchase options[1]	115,564	-
Effect of exchangeable limited partnership units issued to EPCOR for common shares	47,416,000	-
Weighted average number of common shares used in the calculation of diluted earnings per share (all measures)	79,851,254	21,750,000

[1] For the three months ended March 31, 2011, the average market price of the Company's common shares exceeded the exercise price of certain of the granted share purchase options and as a result had a dilutive effect on earnings per share. For the three months ended March 31, 2010, the average market price of the Company's common shares was below the exercise price of all granted share purchase options and as a result none of the share purchase options had a dilutive effect on earnings per share.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

7. Derivative financial instruments and hedge accounting:

Derivative financial and non-financial instruments are held for the purpose of energy purchases, merchant trading or financial risk management.

The derivative instruments assets and liabilities used for risk management purposes consist of the following:

	March 31, 2011				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 1	$ 68	$ 11	$ 4	$ 84
Non-current	9	18	33	-	60
Derivative instruments liabilities:					
Current	(54)	(69)	(5)	-	(128)
Non-current	(75)	(7)	(5)	-	(87)
Net fair value	$ (119)	$ 10	$ 34	$ 4	$ (71)
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(3)	(1)			
Gigajoules of natural gas (millions)	36	4			
Foreign currency (U.S. dollars)			$ (32)		
Interest rate swaps				$ 300	
Range of contract terms in years	0.1 to 5.8	0.1 to 6.8	0.1 to 5.2	7.2	

	December 31, 2010				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 28	$ 113	$ 11	$ -	$ 152
Non-current	16	30	30	-	76
Derivative instruments liabilities:					
Current	(24)	(92)	(3)	(6)	(125)
Non-current	(77)	(7)	(5)	-	(89)
Net fair value	$ (57)	$ 44	$ 33	$ (6)	$ 14
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(3)	(2)			
Gigajoules of natural gas (millions)	38	9			
Foreign currency (U.S. dollars)			$ (302)		
Interest rate swaps				$ 200	
Range of contract terms in years	0.1 to 6.0	0.1 to 7.0	0.1 to 5.5	0.2	

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

7. Derivative financial instruments and hedge accounting, continued:

	January 1, 2010				
	Energy		Foreign exchange	Interest rate	
	Cash flow hedges	Non-hedges	Non-hedges	Non-hedges	Total
Derivative instruments assets:					
Current	$ 15	$ 126	$ 5	$ -	$ 146
Non-current	32	97	26	-	155
Derivative instruments liabilities:					
Current	(23)	(82)	(2)	-	(107)
Non-current	(37)	(54)	(4)	-	(95)
Net fair value	$ (13)	$ 87	$ 25	$ -	$ 99
Net notional buys (sells):					
Megawatt hours of electricity (millions)	(3)	(4)			
Gigajoules of natural gas (millions)	45	13			
Foreign currency (U.S. dollars)			$ (379)		
Interest rate swaps				$ -	
Range of contract terms in years	0.1 to 7.0	0.1 to 4.8	0.1 to 6.0		

Fair values of derivative instruments are determined, when possible, using exchange or over-the-counter price quotations by reference to quoted bid, ask or closing market prices as appropriate, in the most advantageous active market for that instrument. The extent to which fair values of derivative instruments are based on observable market data is determined by the extent to which the market for the underlying commodity is judged to be active. When traded markets are not considered to be sufficiently active or do not exist, the Company uses appropriate valuation and price modeling techniques commonly used by market participants to estimate fair value. The Company may also rely on price forecasts prepared by third party market experts to estimate fair value when there are limited observable prices available. Fair values determined using valuation models require the use of assumptions concerning the amounts and timing of future cash flows. Fair value amounts reflect management's best estimates and maximize, when available, the use of external readily observable market data including future prices, interest rate yield curves, foreign exchange rates, quoted Canadian dollar swap rates, counterparty credit risk, the Company's own credit risk and volatility. When a valuation technique utilizes unobservable market data, no inception gains or losses are recognized, until market quotes or data becomes observable. It is possible that the assumptions used in establishing fair value amounts will differ from future outcomes and the impact of such variations could be material.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

7. Derivative financial instruments and hedge accounting, continued:

Unrealized and realized pre-tax gains and losses on derivative instruments recognized in other comprehensive income and net income were:

	Three months ended March 31, 2011		Three months ended March 31, 2010	
	Unrealized gains (losses)	Realized gains (losses)	Unrealized gains (losses)	Realized gains (losses)
Energy cash flow hedges	$ (61)	$ 4	$ (19)	$ (7)
Energy non-hedges	(33)	(10)	-	11
Foreign exchange non-hedges	1	4	5	3
Interest rate non-hedges	10	(2)	-	-

Realized gains and losses relate only to financial derivative instruments. Included in revenues were losses on financial derivative instruments held at fair value through income or loss of $84 million (three months ended March 31, 2010 – gains of $48 million). Included in energy purchases and fuel were gains on financial instruments held at fair value through income or loss of $52 million (three months ended March 31, 2010 – losses of $36 million). Included in foreign exchange (gains) losses were losses on financial instruments held at fair value through income or loss of $2 million (three months ended March 31, 2010 - nil). Included in finance expense were gains on financial instruments held at fair value through income or loss of $8 million (three months ended March 31, 2010 - nil). Gains and losses on non-financial derivative instrument settlements are recorded in energy purchases and fuel or revenues as appropriate.

If hedge accounting requirements are not met, unrealized and realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel as appropriate. If hedge accounting requirements are met, realized gains and losses on financial energy derivatives are recorded in revenues or energy purchases and fuel, as appropriate, while unrealized gains and losses are recorded in other comprehensive income. Unrealized and realized gains and losses on financial foreign exchange derivatives are recorded in revenues or foreign exchange gains and losses while such gains and losses on financial interest rate derivatives are recorded in finance expense.

The Company has elected to apply hedge accounting on certain derivatives it uses to manage commodity price risk relating to electricity and natural gas prices. For the period ended March 31, 2011, the change in the fair value of the ineffective portion of hedging derivatives required to be recognized as a loss in the statement of income was $1 million (three months ended March 31, 2010 – gain of $1 million).

Net after tax gains and (losses) related to derivative instruments designated as cash flow hedges are expected to settle and be reclassified to net income in the following periods:

	March 31, 2011
Within one year	$ (43)
Between 1 – 5 years	(29)
After more than 5 years	(3)
	$ (75)

The Company's cash flow hedges extend up to 2016.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

8. Share capital:

Authorized shares

	Number of shares authorized
Common shares	unlimited
Preference shares, issuable in series	unlimited
Special voting shares	unlimited
Special limited voting share	one

Issued, called up and fully paid shares

	March 31, 2011		December 31, 2010		January 1, 2010	
	Issued	Outstanding	Issued	Outstanding	Issued	Outstanding
Common shares	40,394,453	$ 925	30,980,500	$ 698	21,750,000	$ 477
Preferred shares, series 1	5,000,000	122	5,000,000	122	-	-
Special voting shares	47,416,000	-	47,416,000	-	56,625,000	-
Special limited voting share	1	-	1	-	1	-
		$ 1,047		$ 820		$ 477

In the first quarter of 2011, the Company closed an offering to sell an additional 9,315,000 common shares, to a syndicate of underwriters, at an offering price of $24.90 per common share for gross proceeds of $232 million, less issue costs of $9 million. Future income tax assets of $2 million related to the share issue costs are recorded in the common share balance. Subsequent to the issue of common shares by the Company, 9,315,000 additional limited partnership units of the Company's subsidiary, CPLP, were issued to another subsidiary of the Company and as a result this transaction reduced EPCOR's ownership interest in CPLP to approximately 54.1% as at March 31, 2011 (December 31, 2010 - 60.5%, January 1, 2010 – 72.2%).

In December 2010, a subsidiary of EPCOR exchanged 9,209,000 of their exchangeable limited partnership units in CPLP on a one-for-one basis for common shares of Capital Power and subsequently entered into an agreement for a secondary offering of 9,209,000 common shares of Capital Power at an offering price of $24.00 per common share.

In December 2010, the Company issued 5 million Cumulative Rate Reset Preferred Shares, series 1 (Series 1 Shares), priced at $25.00 per share for gross proceeds of $125 million, less issue costs of $4 million. Future income tax assets of $1 million related to the share issue costs are recorded in the preferred share balance. The preferred shares will pay fixed cumulative dividends of $1.15 per share per annum, yielding 4.60% per annum, payable on the last business day of March, June, September and December of each year, as and when declared by the board of directors of Capital Power, for the initial five-year period ending December 31, 2015. The dividend rate will be reset on December 31, 2015 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 2.17%. The Series 1 Shares are redeemable by Capital Power, at its option, on December 31, 2015 and on December 31 of every fifth year thereafter.

Holders of Series 1 Shares will have the right to convert all or any part of their shares into Cumulative Floating Rate Preference Shares, Series 2 (the "Series 2 Shares"), subject to certain conditions, on December 31, 2015 and on December 31 of every fifth year thereafter. Holders of Series 2 Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 2.17%, as and when declared by the board of directors of Capital Power.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

8. Share capital, continued:

The special voting shares and special limited voting share were issued to a related party, EPCOR (including subsidiaries of EPCOR). The special limited voting share entitles holders the right to vote as a class on any matter that would: (i) change the location of Capital Power’s head office to a place other than the City of Edmonton in the Province of Alberta; (ii) amend the articles of Capital Power to, or result in a transaction that would, in each case, impact the location of the head office or its meaning as defined in Capital Power’s articles; or (iii) amend the rights attaching to the special limited voting share.

The special voting share holders are entitled to nominate and elect four Directors to the Company's Board of Directors, provided that they own not less than 20% of the aggregate number of outstanding CPC common shares and CPLP exchangeable LP units (exchangeable for CPC common shares). The special voting share holders are entitled to nominate and elect two Directors to the Company's Board of Directors, provided that they own less than 20% but not less than 10% of the aggregate number of outstanding CPC common shares and CPLP exchangeable LP units.

For the three months ended March 31, 2011, dividends of $12 million or 31.5 cents per share have been declared and dividends of $10 million have been paid by the Company to the common share holders (three months ended March 31, 2010 - $7 million or 31.5 cents per share declared and paid). During the three months ended March 31, 2011, dividends of $2 million or 33.08 cents per share have been declared and paid by the Company to preferred share holders with respect to the time period from when the initial share offering closed on December 16, 2010 to March 31, 2011 (three months ended March 31, 2010 – nil).

9. Investments in joint arrangements:

The Company holds 50% interest in the Genesee 3 Project, the Keephills 3 Project and the Taylor’s Coulee Chute Hydro Project, and holds a 40% interest in the Joffre Cogeneration Project. The Company, through its CPILP subsidiary, also holds a 50.15% in the Frederickson power plant.

There are no contingent liabilities relating to Capital Power's interest in the joint arrangements.

Under the terms of the Company’s interest in the Frederickson power plant, the Genesee 3 project and the Keephills 3 Project, the Company and its respective partners have guaranteed financial and performance obligations under the joint arrangements limited to $40 million, $50 million and $50 million respectively.

10. Plants under operating leases:

Certain power generation plants operate under PPAs that convey the right to the holder of the agreement to use the related property plant and equipment. Consequently, these power generation plants held by subsidiaries of the Company, comprised of the Manchief, Mamquam, Moresby Lake, Kenilworth, Greeley, Genesee units 1 and 2, Miller Creek, Brown Lake and Island Generation plants, are accounted for as assets under operating leases.

As at March 31, 2011 the cost of such property, plant and equipment was $1,672 million (December 31, 2010 - $1,419 million, January 1, 2010 - $1,171 million), less accumulated depreciation of $145 million (December 31, 2010 - $93 million, January 1, 2010 - $32 million).

The minimum future rental payments to be received on these PPAs are:

	March 31, 2011	December 31, 2010	January 1, 2010
Due within one year	$ 88	$ 89	$ 76
Due within one to five years	337	340	296
Due more than five years	502	525	529

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

11. Segment information:

The Company operates in one reportable business segment involved in the operation of electrical generation plants within Alberta, British Columbia, Ontario and in the U.S. in California, Colorado, Illinois, New Jersey, New York, North Carolina and Washington, as this is how management assesses performance and determines resource allocations.

The Company's results from operations within each geographic area are:

	Three months ended March 31, 2011				Three months ended March 31, 2010			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Revenues - external	$ 394	$ 64	$ -	$ 458	$ 419	$ 82	$ -	$ 501
Inter-area revenues	1	1	(2)	-	4	4	(8)	-
Total revenues	$ 395	$ 65	$ (2)	$ 458	$ 423	$ 86	$ (8)	$ 501

	As at March 31, 2011				As at December 31, 2010			
	Canada	U.S.	Inter-area eliminations	Total	Canada	U.S.	Inter-area eliminations	Total
Property, plant and equipment	$ 3,217	$ 489	$ -	$3,706	$3,174	$ 504	$ -	$3,678
Intangible assets	366	264	-	630	373	278	-	651
Goodwill	29	74	-	103	29	75	-	104
Other assets	20	-	-	20	19	-	-	19
	$ 3,632	$ 827	$ -	$4,459	$3,595	$ 857	$ -	$4,452

	As at January 1, 2010			
	Canada	U.S.	Inter-area eliminations	Total
Property, plant and equipment	$2,790	$ 555	$ -	$3,345
Intangible assets	382	320	-	702
Goodwill	52	76	-	128
Other assets	20	-	-	20
	$3,244	$ 951	$ -	$4,195

12. Subsequent events:

Acquisition

During the three months ended March 31, 2011, a subsidiary of the Company entered into an agreement to acquire one hundred per cent of the equity interests in Bridgeport Energy, LLC, which owns the Bridgeport Energy facility (Bridgeport Energy), from a third party. Bridgeport Energy is a natural gas-fired combined cycle power generation facility located in Bridgeport, Connecticut, with a nominal capacity of 520 MW. This transaction closed April 28, 2011. The US$355 million cash purchase price for the acquisition is subject to working capital adjustments and other customary closing adjustments.

This acquisition supports the Company's growth strategy and is consistent with the Company's technology and operating focus.

As at April 28, 2011, the initial accounting for the above transaction is incomplete due to the proximity of the closing date to the release of the condensed interim consolidated financial statements for the three months ended March 31, 2011. As a result, the following items were not available for disclosure in these condensed interim consolidated financial statements for the three months ended March 31, 2011 but will be presented in the condensed interim consolidated financial statements for the six months ended June 30, 2011:

- the fair value, gross contractual, and best estimate at the acquisition date of the contractual cash flows not expected to be collected for acquired receivables;
- amounts recognized as of the acquisition date for each major class of assets acquired and liabilities assumed;
- the estimated amount, if any, of goodwill, though if any, none would be expected to be deductible for tax purposes and;
- the revenue and income or loss of the combined entity for the current reporting period as though the acquisition date for all business combinations that occurred during the year had been as of the beginning of the reporting period.

Debt Issuance

On April 18, 2011, the Company's subsidiary, CPLP, issued $300 million of unsecured medium-term notes due in 2015 with interest payable semi-annually at 4.6% commencing on June 1, 2011.

13. Transition to IFRS:

As noted in note 2, this is the first period under which the Company's condensed interim consolidated financial statements have been presented in accordance with IFRS. For all periods up to and including the year ended December 31, 2009, the Company prepared its financial statements in accordance with previous Canadian GAAP.

In accordance with the Canadian Institute of Chartered Accountants' adoption of IFRS, the Company has prepared financial statements which comply with IFRS applicable for periods beginning on or after January 1, 2010 as described in note 2. In preparing these financial statements, the Company's opening statement of financial position was prepared as at January 1, 2010, the Company's date of transition to IFRS. This note explains the principal adjustments made by the Company in restating its Canadian GAAP statement of financial position as at January 1, 2010, and its previously published Canadian GAAP financial statements for the three months ended March 31, 2010 and the year ended December 31, 2010. Estimates made under IFRS as at January 1, 2010 are consistent with estimates made for the same date under previous GAAP.

The Company has applied the following optional exemptions and exceptions in its transition from Canadian GAAP to IFRS:

Business combinations

IFRS 1 provides the option to apply IFRS 3, Business Combinations, retrospectively or prospectively from the date of transition. The retrospective basis would require restatement of all business combinations that occurred prior to the transition date. The Company has taken the IFRS 1 election to not restate previous business combinations at the date of transition. Any goodwill arising on such business combinations before the date of transition has not been adjusted from its carrying amount previously determined under Canadian GAAP as a result of applying this exemption. Goodwill and indefinite life intangibles are tested annually for impairment. Refer to the accounting policy on impairment of non-financial assets disclosed in note 2(n).

Employee benefits

The Company has elected, under IFRS 1, to recognize all cumulative actuarial gains and losses that were deferred previously under Canadian GAAP through opening retained earnings at the date of transition for all of its employee benefit plans.

Translation of foreign operations

The Company has elected, under IFRS 1, to deem the cumulative translation account for all foreign operations to be nil at the date of transition, and to reclassify all amounts determined in accordance with previous GAAP at that date to retained earnings.

Decommissioning liabilities

The Company has elected, under IFRS 1, to adopt a simplified approach, whereby the Company elected to not calculate retrospectively the effect of each change in estimate that occurred prior to the date of transition.

Fair value as deemed cost

The Company has elected, under IFRS 1, to use fair value as deemed cost on certain items of property, plant and equipment.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Transition to IFRS, continued:

Adjustments to the statement of cash flows

In addition to the adjustments required for the accounting policy differences described in the following notes, interest paid, including capitalized interest, and income taxes paid and recovered have been moved into the body of the consolidated statement of cash flows within operating and financing activities. These amounts were previously disclosed as supplementary information and captured within the consolidated statement of cash flows within changes in non-cash operating working capital for expensed interest and income taxes and within payments to acquire property, plant and equipment and other assets for capitalized interest. There are no other material differences between the statement of cash flows presented under IFRS and the statement of cash flows presented under Canadian GAAP.

Reconciliation of equity

The reconciliation of equity reported under previous Canadian GAAP to equity reported under IFRS on first time adoption as at January 1, 2010 (date of transition to IFRS) was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation Reclassifications (e)	IFRS
Cash and cash equivalents	$ 52	$ -	$ -	$ -	$ -	$ -	$ 52
Trade and other receivables[1]	312	1	-	-	2	-	315
Inventories	63	5	-	-	-	-	68
Derivative financial instruments assets	146	-	-	-	-	-	146
Deferred tax assets	2	-	-	-	-	(2)	-
Assets held for sale	36	-	-	-	-	-	36
Total current assets	611	6	-	-	2	(2)	617
Other assets	120	-	-	-	-	(100)	20
Derivative financial instruments assets	155	-	-	-	-	-	155
Finance lease receivables	-	-	-	-	64	27	91
Other financial assets	-	-	-	-	(3)	73	70
Deferred tax assets	61	-	-	-	(30)	2	33
Intangible assets	712	-	(10)	-	-	-	702
Property, plant and equipment	3,237	19	(28)	53	34	30	3,345
Goodwill	140	-	(12)	-	-	-	128
Total non-current assets	4,425	19	(50)	53	65	32	4,544
Total assets	$ 5,036	$ 25	$ (50)	$ 53	$ 67	$ 30	$ 5,161

[1] Includes accounts receivable, income taxes recoverable and prepaid expenses.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Transition to IFRS, continued:

Reconciliation of equity continued:

As at January 1, 2010:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation Reclassifications (e)	IFRS
Trade and other payables	$ 339	$ -	$ -	$ -	$ -	$ (14)	$ 325
Derivative financial instruments liabilities	108	(1)	-	-	-	-	107
Loans and borrowings	247	-	-	-	-	-	247
Deferred revenue and other liabilities	8	-	-	-	-	-	8
Deferred tax liabilities	21	-	-	-	-	(21)	-
Provisions	-	(6)	-	-	-	14	8
Total current liabilities	723	(7)	-	-	-	(21)	695
Derivative financial instruments liabilities	102	(7)	-	-	-	-	95
Loans and borrowings	1,472	-	-	-	-	-	1,472
Deferred revenue and other liabilities	109	19	-	-	-	(73)	55
Deferred tax liabilities	95	-	-	-	(24)	21	92
Provisions	-	33	-	-	-	103	136
Total non-current liabilities	1,778	45	-	-	(24)	51	1,850
Share capital	477	-	-	-	-	-	477
Retained earnings	7	(2)	(6)	1	7	-	7
Other reserves	5	-	-	4	-	-	9
Equity attributable to shareholders of the Company	489	(2)	(6)	5	7	-	493
Non-controlling interests	2,046	(11)	(44)	48	84	-	2,123
Total equity	2,535	(13)	(50)	53	91	-	2,616
Total liabilities and equity	$ 5,036	$ 25	$ (50)	$ 53	$ 67	$ 30	$ 5,161

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Transition to IFRS, continued:

Reconciliation of equity, continued:

The reconciliation of equity reported under previous Canadian GAAP to equity under IFRS (First time adoption) as at March 31, 2010 (end of comparative period) was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation Reclassifications (e)	IFRS
Cash and cash equivalents	$ 65	$ -	$ -	$ -	$ -	$ -	$ 65
Trade and other receivables[1]	224	-	-	-	2	-	226
Inventories	68	5	-	-	-	-	73
Derivative financial instruments assets	174	-	-	-	-	-	174
Deferred tax assets	12	-	-	-	-	(12)	-
Assets held for sale	-	-	-	-	-	-	-
Total current assets	543	5	-	-	2	(12)	538
Other assets	116	-	-	-	-	(96)	20
Derivative financial instruments assets	155	-	-	-	-	-	155
Finance lease receivables	-	-	-	-	63	26	89
Other financial assets	-	-	-	-	-	70	70
Deferred tax assets	59	-	-	-	(34)	12	37
Intangible assets	686	-	(10)	-	-	-	676
Property, plant and equipment	3,255	8	(27)	49	35	31	3,351
Goodwill	138	-	(12)	-	-	-	126
Total non-current assets	4,409	8	(49)	49	64	43	4,524
Total assets	$ 4,952	$ 13	$ (49)	$ 49	$ 66	$ 31	$ 5,062

[1] Includes accounts receivable, income taxes recoverable and prepaid expenses.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Transition to IFRS, continued:

Reconciliation of equity, continued:

As at March 31, 2010:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation Reclassifications (e)	IFRS
Trade and other payables	$ 280	$ 2	$ -	$ -	$ -	$ (17)	$ 265
Derivative financial instruments liabilities	132	(1)	-	-	-	-	131
Loans and borrowings	247	-	-	-	-	-	247
Deferred revenue and other liabilities	7	-	-	-	-	-	7
Deferred tax liabilities	19	-	-	-	-	(19)	-
Provisions	-	(7)	-	-	-	17	10
Total current liabilities	685	(6)	-	-	-	(19)	660
Derivative financial instruments liabilities	118	(7)	-	-	-	-	111
Loans and borrowings	1,387	-	-	-	-	-	1,387
Deferred revenue and other liabilities	107	18	-	-	-	(70)	55
Deferred tax liabilities	85	-	-	-	(30)	19	74
Provisions	-	31	-	-	1	101	133
Total non-current liabilities	1,697	42	-	-	(29)	50	1,760
Share capital	477	-	-	-	-	-	477
Retained earnings	13	(4)	(6)	-	9	-	12
Other reserves	5	-	-	4	1	-	10
Equity attributable to shareholders of the Company	495	(4)	(6)	4	10	-	499
Non-controlling interests	2,075	(19)	(43)	45	85	-	2,143
Total equity	2,570	(23)	(49)	49	95	-	2,642
Total liabilities and equity	$ 4,952	$ 13	$ (49)	$ 49	$ 66	$ 31	$ 5,062

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Transition to IFRS, continued:

Reconciliation of equity, continued:

The reconciliation of equity reported under previous Canadian GAAP to equity under IFRS (First time adoption) as at December 31, 2010 (end of comparative period) was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation Reclassifications (e)	IFRS
Cash and cash equivalents	$ 56	$ -	$ -	$ -	$ -	$ -	$ 56
Trade and other receivables[1]	284	-	-	-	2	-	286
Inventories	55	5	-	-	-	-	60
Derivative financial instruments assets	152	-	-	-	-	-	152
Deferred tax assets	7	-	-	-	-	(7)	-
Assets held for sale	-	-	-	-	-	-	-
Total current assets	554	5	-	-	2	(7)	554
Other assets	121	-	-	-	-	(102)	19
Derivative financial instruments assets	76	-	-	-	-	-	76
Finance lease receivables	-	-	-	-	61	24	85
Other financial assets	-	-	-	-	11	78	89
Deferred tax assets	63	-	-	-	(30)	7	40
Intangible assets	667	-	(16)	-	-	-	651
Property, plant and equipment	3,597	24	(61)	45	40	33	3,678
Goodwill	139	-	(35)	-	-	-	104
Total non-current assets	4,663	24	(112)	45	82	40	4,742
Total assets	$ 5,217	$ 29	$ (112)	$ 45	$ 84	$ 33	$ 5,296

[1] Includes accounts receivable, income taxes recoverable and prepaid expenses.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Transition to IFRS, continued:

Reconciliation of equity, continued:

As at December 31, 2010:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (a)	IAS 36 Impact (b)	IFRS 1 elections (c)	Other impacts (d)	Presentation Reclassifications (e)	IFRS
Trade and other payables	$ 304	$ 4	$ -	$ -	$ -	$ (26)	$ 282
Derivative financial instruments liabilities	126	(1)	-	-	-	-	125
Loans and borrowings	235	-	-	-	-	-	235
Deferred revenue and other liabilities	10	-	-	-	-	-	10
Deferred tax liabilities	21	-	-	-	-	(21)	-
Provisions	-	(6)	-	-	-	26	20
Total current liabilities	696	(3)	-	-	-	(21)	672
Derivative financial instruments liabilities	95	(6)	-	-	-	-	89
Loans and borrowings	1,634	-	-	-	-	-	1,634
Deferred revenue and other liabilities	119	20	-	-	-	(78)	61
Deferred tax liabilities	95	-	-	-	(43)	21	73
Provisions	-	41	-	-	3	111	155
Total non-current liabilities	1,943	55	-	-	(40)	54	2,012
Share capital	820	-	-	-	-	-	820
Retained earnings	3	(1)	(1)	(1)	8	-	8
Other reserves	1	-	(3)	4	3	-	5
Equity attributable to shareholders of the Company	824	(1)	(4)	3	11	-	833
Non-controlling interests	1,754	(22)	(108)	42	113	-	1,779
Total equity	2,578	(23)	(112)	45	124	-	2,612
Total liabilities and equity	$ 5,217	$ 29	$ (112)	$ 45	$ 84	$ 33	$ 5,296

13. Transition to IFRS, continued:

Notes to the reconciliations

The tables above present the aggregate transitional adjustments from previous Canadian GAAP to IFRS. The following notes summarize the key differences noted on transition to IFRS.

(a) IAS 16 Property, Plant and Equipment & IAS 37 Provisions:

The contract between the Genesee mine operator and the Company requires the operating activities of the mine, including depreciation on the operator's share of the mine assets, to be fully funded by the Company, whereas the capital funding is shared by the two parties. As a result, certain costs that were previously capitalized would have been expensed under the requirements of IAS 16 and fully funded by Capital Power resulting in an increase to non-current deferred revenue and other liabilities of $11 million as at January 1, 2010 and March 31, 2010 and an increase of $14 million as at December 31, 2010. As a result of these changes, trade and other payables of $1 million and $4 million were recorded as at March 31, 2010 and December 31, 2010 respectively. In addition, the Company recorded a transitional adjustment to align accounting policies between the Company and the Genesee mine operator resulting in an increase of $5 million in inventory, a decrease of $3 million to property, plant and equipment and an increase in non-current deferred revenue and other liabilities of $2 million as at January 1, 2010 through December 31, 2010.

Under Canadian GAAP, the Joffre joint venture's overhaul costs for the Joffre cogeneration facility were expensed and the joint venture's recovery of overhaul costs from one of the joint venture partners was recognized as revenue in the period that the cost was incurred. Under the requirements of IAS 16, the overhaul costs are capitalized as a component of property, plant and equipment and recoveries are recognized in income over the period that the corresponding asset is depreciated. Therefore deferred revenue and other liabilities increased by $6 million, $5 million and $4 million, as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively, on transition to IFRS for recoveries received by the joint venture of costs that had been expensed under Canadian GAAP and reclassified to property, plant and equipment under IFRS. As a result of these changes, trade and other receivables of $1 million were recorded as at January 1, 2010 and trade and other payables of $1 million were recorded as at March 31, 2010

Under IFRS, accounting for the components of property, plant and equipment is required at a more detailed level than under Canadian GAAP. IAS 16 requires separate depreciation for those components with a distinct depreciation method or rate of deprecation. As a result of applying the componentization requirements of IAS 16 effective July 1, 2009, the net book value of property, plant and equipment decreased by $5 million, $14 million and $12 million, reflecting increased depreciation net of overhaul costs capitalized, as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively.

IAS 37 requires provisions to be measured at the best estimate of the expected expenditure using discount rates appropriate for each liability. Under Canadian GAAP the provision was measured at fair value. The provision is to be re-measured at each reporting period for any changes in cash flow estimates, timing of decommissioning activity and discount rates. Accordingly, the Company re-measured its decommissioning liabilities (asset retirement obligations) using revised cash flow estimates with respect to the Genesee Mine as well as for revised discount rates for all decommissioning liabilities. The re-measurement of the decommissioning liabilities resulted in decreases of $7 million, $8 million and $7 million to the current provision and increases of $22 million, $22 million and $37 million to the non-current provision as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively. The re-measurement of the decommissioning liability also resulted in increases of $27 million, $25 million and $39 million to the associated property, plant and equipment as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively.

13. Transition to IFRS, continued:

Notes to the reconciliations, continued

(a) IAS 16 Property, Plant and Equipment & IAS 37 Provisions, continued:

Under IFRS, amounts provided for the unavoidable costs of the Company's Alberta retail and commercial natural gas contracts are recognized as provisions in the financial statements. Accordingly, the Company has reclassified $1 million from current derivative financial instruments liabilities to current provisions as at January 1, 2010. As well, related to these contracts, the Company recognized an additional $11 million in non-current provisions as at January 1, 2010 of which $7 million was reclassified from non-current derivative financial instruments liabilities as at January 1, 2010. As a result of changes in cash flow assumptions and discount rates, the non-current provision decreased by $2 million and $7 million as at March 31, 2010 and December 31, 2010 respectively. Included in the December 31, 2010 change in the non-current provision is a $1 million reduction in the January 1, 2010 reclassification from non-current derivative financial instruments liabilities.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in decreases of $2 million, $4 million and $1 million in the equity attributable to shareholders and decreases of $11 million, $19 million and $22 million to non-controlling interests as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively.

(b) IAS 36 – Impairment of Assets:

IAS 36 requires that impairment testing be done on a CGU level, which is the smallest identifiable group of assets that generates cash inflows. For Capital Power, some CGUs consist of a single plant resulting in more CGUs subject to impairment testing under IFRS than under Canadian GAAP. In addition, any goodwill amounts must be allocated and included in the impairment test for each CGU. Accordingly, this change may result in more frequent write downs of goodwill under IFRS.

IAS 36 also requires a one-step approach to determine the recoverable amount of a CGU. Canadian GAAP's two-step approach required the application of discounted cash flow techniques to measure the impairment amount, but only after the use of undiscounted cash flow analysis indicated the existence of an impairment. The adoption of IAS 36 is expected to result in more frequent write downs since the carrying amount of assets which are supported by undiscounted cash flows may be determined to be impaired when the future cash flows are discounted in accordance with the IFRS requirements. Unlike Canadian GAAP, previous impairment losses may be reversed or reduced if the circumstances which lead to the impairment change, except for impairment losses attributed to goodwill.

In accordance with IAS 36, the Company reviewed the recoverable amount for its CGUs with allocated goodwill at both the date of transition to IFRS and as at December 31, 2010. The key assumptions used in those reviews are disclosed in note 14(d). For all other CGUs, management assessed whether there were any triggering events at both the date of transition to IFRS and as at December 31, 2010. Recoverable amounts were calculated on a fair value less cost to sell basis, using discounted cash flow models based on the Company's long-term planning model. As a result of the review of recoverable amounts it was determined that certain of the Company's CGUs were impaired.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Transition to IFRS, continued:

Notes to the reconciliations, continued

(b) IAS 36 – Impairment of Assets, continued:

The impacts of the impairments by CGU and by line item, excluding the impacts on depreciation and foreign currency translation, as at January 1, 2010, March 31, 2010 and December 31, 2010 were:

	Goodwill			Intangible assets			Property, plant and equipment			Total		
	December 31, 2010	March 31, 2010	January 1, 2010	December 31, 2010	March 31, 2010	January 1, 2010	December 31, 2010	March 31, 2010	January 1, 2010	December 31, 2010	March 31, 2010	January 1, 2010
CPILP manager contracts	$ -	$ -	$ -	$ 7	$ 7	$ 7	$ -	$ -	$ -	$ 7	$ 7	$ 7
Calstock	9	9	9	5	1	1	28	8	8	42	18	18
Greeley	-	-	-	-	-	-	7	7	7	7	7	7
Kapuskasing	10	-	-	2	-	-	5	-	-	17	-	-
Moresby Lake	2	2	2	-	1	1	-	2	2	2	5	5
Naval Training Centre	1	1	1	1	1	1	-	-	-	2	2	2
North Bay	10	-	-	-	-	-	1	-	-	11	-	-
Roxboro	-	-	-	-	-	-	11	11	11	11	11	11
Tunis	3	-	-	2	-	-	12	-	-	17	-	-
	$ 35	$ 12	$ 12	$ 17	$ 10	$ 10	$ 64	$ 28	$ 28	$ 116	$ 50	$ 50

The impairments noted above for Greeley, Naval Training Centre, Roxboro and $2 million of the CPILP manager contract impairments are reported in the U.S. segment while the impairments for Calstock, Kapuskasing, Moresby Lake, North Bay, Tunis and $5 million of the CPILP manager contract impairments are reported in the Canadian segment.

As a result of the change in impairment testing under IFRS to a one-step discounted cash flow test, the Company has determined that the carrying amount of the CPILP manager contracts was in excess of the fair value less cost to sell for the contracts, resulting in the impairment noted above.

The impairment recorded for the Calstock facility at January 1, 2010 was a result of higher than expected wood waste costs due to declines in wood waste availability caused by weakness in the Ontario forestry sector. The impairments recorded for the Greeley and Roxboro facilities at January 1, 2010 were due to the impact of weakening economic conditions in their respective markets.

The additional impairment recorded for the Calstock facility, as well as the impairments recorded for the Kapuskasing, North Bay and Tunis facilities in the third quarter of 2010 were primarily due to lower expectations for waste heat as a result of lower expected throughput on the pipeline that provides the waste heat.

The total adjustments resulting from IAS 36, including resulting impacts on depreciation and foreign currency translation gains and losses, impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in decreases of $6 million, $6 million and $4 million in the equity attributable to shareholders and decreases of $44 million, $43 million and $108 million to non-controlling interests as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively.

13. Transition to IFRS, continued:

Notes to the reconciliations, continued

(c) IFRS 1 – First Time Adoption of IFRS:

IFRS 1 – First Time Adoption of IFRS provides an election to deem any cumulative translation differences to be zero on transition to IFRS. As a result of the Company taking the IFRS 1 election to adjust the balance of its cumulative translation account to nil at the date of transition, $4 million was reclassified within equity, between accumulated other comprehensive income and retained earnings at January 1, 2010.

IFRS 1 also provides an optional election on transition to IFRS which allows the use of fair value as deemed cost on items of property, plant and equipment. The Company has elected under IFRS 1 to fair value certain items of property, plant and equipment resulting in an increase to property, plant and equipment of $53 million as at January 1, 2010. As a result of the increased cost base, property, plant and equipment was impacted by higher foreign exchange and depreciation changes which result in decreases of $4 million and $8 million as at March 31, 2010 and December 31, 2010 respectively.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in increases of $5 million, $4 million and $3 million in the equity attributable to shareholders and increases of $48 million, $45 million and $42 million to non-controlling interests as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively.

(d) Other Impacts:

In accordance with IAS 17 – Leases, the Kingsbridge PPA was determined to be a finance lease. The transitional adjustment was a result of IAS 17 and Canadian GAAP having different qualitative guidelines in the determination of the classification of leases between operating and finance (or capital under Canadian GAAP). As a result, property, plant and equipment was decreased by $53 million, finance lease receivable was increased by $64 million, trade and other receivables was increased by $2 million and retained earnings was increased by $13 million as at January 1, 2010. Increases to property, plant and equipment and decreases to finance lease receivable were $1 million and $3 million as at March 31, 2010 and December 31, 2010 respectively with no net impact to equity.

In accordance with IAS 31 – Interests in Joint Ventures, the Company has concluded that it controls the Genesee mine joint venture and as a result is required to consolidate this investment under IFRS. As a result, property plant and equipment was increased by $87 million, $87 million and $90 million as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively, with the full amount of the changes being attributed to non-controlling interests.

The Company has elected, under IFRS 1, to recognize all actuarial gains and losses in other comprehensive income. Under Canadian GAAP, the Company recognized actuarial gains and losses into income or loss using the corridor approach whereby amounts that exceeded the corridor were recognized into income or loss over the average remaining service period of the active employees. At the date of transition, all previously unrecognized cumulative actuarial gains and losses were recognized in retained earnings. As at March 31, 2010 and December 31, 2010, the provision increased by $1 million and $3 million respectively with the offset to other comprehensive income.

IAS 39 - Financial Instruments, requires an asset classified as available for sale to be recorded at fair value with any changes in the fair value recognized in other comprehensive income. Accordingly, other financial assets were reduced by $3 million as at January 1, 2010, changed by nil at March 31, 2010 and increased by $11 million as at December 31, 2010, for the difference between the fair value and the previously reported carrying amount for one of the Company's equity investments. Since these adjustments are unrealized, accumulated other comprehensive income was decreased or increased in the respective periods.

13. Transition to IFRS, continued:

Notes to the reconciliations, continued

(d) Other Impacts, continued:

In addition to the IAS 39 impacts above, under IAS 39, hedge effectiveness testing must incorporate the entity's credit risk. The net impacts of the IAS 39 changes were increases to accumulated other comprehensive income of nil, $1 million and $3 million as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively, with corresponding changes to retained earnings.

Other impacts also includes the impact of tax on the IFRS adjustments recognized. To recognize the income tax impact of the IFRS transition adjustments, deferred tax assets were decreased by $30 million, $34 million and $30 million and deferred tax liabilities were decreased by $24 million, $30 million and $43 million as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively.

These adjustments impact equity in proportion to the Company's owners' respective shares of the adjustments and accordingly resulted in increases of $7 million, $10 million and $11 million in the equity attributable to shareholders and increases of $84 million, $85 million and $113 million to non-controlling interests as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively.

(e) Presentation reclassifications:

IAS 1 – Presentation of Financial Statements, provides presentation requirements for the statement of financial position. Accordingly, the following items have been reclassified:

- Financial assets must be presented separately from other assets. Accordingly, $27 million, $26 million and $24 million were reclassified from other assets to finance lease receivables and $73 million, $70 million and $78 million were reclassified from other assets to other financial assets as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively.

- Provisions must be presented as a separate item on the statement of financial position. Accordingly, $14 million, $17 million and $26 million were reclassified from accounts payable to current provisions and $103 million, $101 million and $111 million were reclassified from other non-current liabilities to non-current provisions as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively.

- Deferred tax balances are to be classified as non-current. Therefore, as at January 1, 2010, the current deferred tax assets and liabilities of $2 million and $21 million respectively, were reclassified to non-current deferred tax assets and liabilities respectively. As at March 31, 2010, current deferred tax assets and liabilities of $12 million and $19 million respectively, were reclassified to non-current deferred tax assets and liabilities respectively. As at December 31, 2010, current deferred tax assets and liabilities of $7 million and $21 million respectively, were reclassified to non-current deferred tax assets and liabilities respectively.

- International Financial Reporting Interpretations Committee (IFRIC) 18 requires that contributions received with respect to the construction of property, plant and equipment and used to provide goods or services, be classified as deferred revenue. Accordingly, $30 million, $31 million and $33 million of contributions that were previously reported as reductions of property, plant and equipment were reclassified as increases in deferred revenue and other liabilities as at January 1, 2010, March 31, 2010 and December 31, 2010 respectively.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Transition to IFRS, continued:

Reconciliation of total comprehensive income

The reconciliation of total comprehensive income reported under previous Canadian GAAP for the three months ended March 31, 2010 to total comprehensive income reported under IFRS was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (f)	IAS 36 Impact (g)	IFRS 1 elections (h)	Other impacts (i)	Presentation Reclassifications (j)	IFRS
Revenues	$ 485	$ -	$ -	$ -	$ (1)	$ -	$ 484
Other income	14	1	-	-	1	1	17
Energy purchases and fuel	(283)	(2)	-	-	1	-	(284)
Gross income	216	(1)	-	-	1	1	217
Operations, maintenance and direct administration	(44)	-	-	-	-	44	-
Indirect administration	(26)	-	-	-	-	26	-
Other raw materials and operating charges	-	-	-	-	-	(19)	(19)
Staff costs and employee benefits expense	-	-	-	-	-	(41)	(41)
Depreciation and amortization	(46)	(9)	1	(1)	(2)	-	(57)
Other administrative expenses	-	-	-	-	-	(10)	(10)
Property taxes	(5)	-	-	-	-	-	(5)
Foreign exchange losses	(1)	-	-	-	-	-	(1)
Operating income	94	(10)	1	(1)	(1)	1	84
Gain on sale of power syndicate agreement	28	-	-	-	-	-	28
Finance expense	(18)	-	-	-	-	(1)	(19)
Income before tax	104	(10)	1	(1)	(1)	-	93
Income tax (expense) recovery	-	-	-	-	(1)	-	(1)
Net income	104	(10)	1	(1)	(2)	-	92
Other comprehensive income (loss)	(31)	-	1	(3)	4	-	(29)
Total comprehensive income	73	(10)	2	(4)	2	-	63
Attributable to:							
Non-controlling interests	$ 60	$ (8)	$ 1	$ (3)	$ 1	$ -	$ 51
Shareholders of the Company	$ 13	$ (2)	$ 1	$ (1)	$ 1	$ -	$ 12

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Transition to IFRS, continued:

Reconciliation of total comprehensive income, continued

The reconciliation of total comprehensive income reported under previous Canadian GAAP for the year ended December 31, 2010 to total comprehensive income reported under IFRS was as follows:

	Canadian GAAP	IAS 16 & IAS 37 Impacts (f)	IAS 36 Impact (g)	IFRS 1 elections (h)	Other impacts (i)	Presentation Reclassifications (j)	IFRS
Revenues	$ 1,712	$ -	$ -	$ -	$ (5)	$ -	$ 1,707
Other income	48	1	-	-	2	4	55
Energy purchases and fuel	(992)	(2)	-	-	4	-	(990)
Gross income	768	(1)	-	-	1	4	772
Operations, maintenance and direct administration	(230)	-	-	-	-	230	-
Indirect administration	(133)	-	-	-	-	133	-
Other raw materials and operating charges	-	29	-	-	-	(133)	(104)
Staff costs and employee benefits expense	-	-	-	-	(1)	(174)	(175)
Depreciation and amortization	(197)	(39)	3	(3)	(7)	2	(241)
Impairments	-	-	(66)	-	-	1	(65)
Other administrative expenses	-	-	-	-	-	(57)	(57)
Property taxes	(18)	-	-	-	-	-	(18)
Foreign exchange losses	(1)	-	-	-	-	-	(1)
Operating income	189	(11)	(63)	(3)	(7)	6	111
Gains on acquisitions and disposals	30	-	-	-	-	-	30
Finance expense	(74)	2	-	-	-	(6)	(78)
Income before tax	145	(9)	(63)	(3)	(7)	-	63
Income tax (expense) recovery	(8)	-	-	-	22	-	14
Net income	137	(9)	(63)	(3)	15	-	77
Other comprehensive income	(57)	1	1	(5)	3	-	(57)
Total comprehensive income (loss)	80	(8)	(62)	(8)	18	-	20
Attributable to:							
Non-controlling interests	75	(10)	(65)	(7)	18	-	11
Shareholders of the Company	$ 5	$ 2	$ 3	$ (1)	$ -	$ -	$ 9

13. Transition to IFRS, continued:

Notes to the reconciliations

The tables above present the aggregate transitional adjustments from previous Canadian GAAP to IFRS. The following notes summarize the key differences noted on transition to IFRS.

(f) IAS 16 Property, Plant and Equipment & IAS 37 Provisions:

As noted in the reconciliation of equity on transition, as a result of the Company re-measuring its commercial natural gas contracts, other income increased by $1 million for the three months ended March 31, 2010 and for the twelve months ended December 31, 2010.

Energy purchases and fuel costs increased by $2 million for the three months ended March 31, 2010 and for the twelve months ended December 31, 2010 as a result of the increase to coal costs due to costs that were previously capitalized under GAAP which are expensed under IFRS.

Other raw materials and operating charges used decreased by nil for the three months ended March 31, 2010 and $29 million for the twelve months ended December 31, 2010 as a result of capitalizing the overhaul costs which had previously been expensed under GAAP.

The impact to depreciation and amortization as a result of implementing IAS 16 is an increase of $8 million for the three months ended March 31, 2010 and $33 million for the twelve months ended December 31, 2010.

Depreciation and amortization expense was increased by $1 million for the three months ended March 31, 2010 and $6 million for the twelve months ended December 31, 2010, as a result of implementing IAS 37 which resulted in an increase in the value of decommissioning assets on transition.

Finance costs decreased by nil for the three months ended March 31, 2010 and $2 million for the twelve months ended December 31, 2010 as a result of accretion expense being lower as a result of implementing IAS 37.

(g) IAS 36 Impairments:

The Company recognized certain impairments against property, plant and equipment, intangible assets and goodwill on transition to IFRS. As a result of these impairments, the Company's depreciation and amortization expense decreased by $1 million for the three months ended March 31, 2010 and $3 million for the twelve months ended December 31, 2010.

During the third quarter of 2010, additional asset impairments were recorded for $66 million.

(h) IFRS 1 First Time Adoption of IFRS:

As noted in the reconciliation of equity on transition, the Company elected to use the fair value at transition date as deemed cost for certain plants. As a result of this election, the Company's depreciation and amortization expense has increased by $1 million for the three months ended March 31, 2010 and $3 million for the twelve months ended December 31, 2010.

(i) Other Impacts:

As noted in the reconciliation of equity on transition, one of the Company's power purchase arrangements was determined to be a finance lease which resulted in a reduction to property, plant and equipment and an increase to finance lease receivable. As such, there was a reduction to electricity sales revenues of $1 million for the three months ended March 31, 2010 and $5 million for the twelve months ended December 31, 2010, an increase to other income of $1 million for the three months ended March 31, 2010 and $2 million for the twelve months ended December 31, 2010 and a reduction to depreciation and amortization of $1 million for the three months ended March 31, 2010 and $3 million for the twelve months ended December 31, 2010.

13. Transition to IFRS, continued:

Notes to the reconciliations, continued

(i) Other impacts, continued:

As noted in the reconciliation of equity on transition, the Company has concluded that it controls the Genesee mine joint venture and as a result is required to consolidate this investment under IFRS. As a result, depreciation and amortization increased by $3 million and $10 million for the three months ended March 31, 2010 and for the twelve months ended December 31, 2010 respectively, with the full amount of the changes being attributed to non-controlling interests.

The impact of incorporating the Company's credit risk in the hedge effectiveness testing under IAS 39, is a reduction to energy purchases and fuel of $1 million for the three months ended March 31, 2010 and $4 million for the twelve months ended December 31, 2010 with an offsetting charge to other comprehensive income (OCI).

As a result of the IFRS adjustments, the impact to income taxes for the three months ending March 31, 2010 is an increase in expenses of $1 million and the impact for the twelve months ending December 31, 2010 is a decrease in expenses of $22 million.

The remaining adjustments impact OCI:

- The impact of using Primary Energy Recycling Corporation's share price as a proxy to determine the fair value of the Company's investment in Primary Energy Recycling Holdings LLC, is an increase to OCI of $2 million (net of nil in income tax expense) for the three months ended March 31, 2010 and $9 million (net of $4 million in income tax expense) for the twelve months ended December 31, 2010.
- The impact of incorporating the entity's credit risk into the hedge effectiveness testing was a decrease in OCI of $1 million (net of income tax expense of nil) for the three months ended March 31, 2010 and a decrease of $4 million (net of income tax expense of nil) for the twelve months ended December 31, 2010.
- The impact of recognizing all actuarial gains and losses in other comprehensive income as incurred was to decrease OCI by $1 million (net of income tax recovery of nil) and $2 million (net of income tax recovery of $1 million) for the three months ended March 31, 2010 and for the twelve months ended December 31, 2010 respectively.
- As a result of the adjustments made by the Company on transition and up to March 31, 2010, there is a net increase to OCI for a reduction in the unrealized losses on translating the Company's foreign operations of $2 million (net of $2 million in income tax recovery) for the three months ended March 31, 2010 and a net decrease to OCI of $3 million (net of $1 million in income tax expense) for the twelve months ended December 31, 2010.

(j) Presentation reclassifications:

The following items have been reclassified:

- In accordance with IFRIC 18, International Financial Reporting Interpretations Committee (IFRIC) 18 requires that contributions received with respect to the construction of property, plant and equipment and used to provide goods or services, be classified as deferred revenue. Accordingly, revenue should be recorded as the contributions are realized, whereas, previously under GAAP, this was recorded as a reduction of depreciation. The impact is an increase to other income and an increase to depreciation expense of $1 million for the three months ended March 31, 2010 and $4 million for the twelve months ended December 31, 2010.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

13. Transition to IFRS, continued:

Notes to the reconciliations, continued

(j) Presentation reclassifications, continued:

- The Company has chosen to present its statement of income by nature of expense. Certain amounts have been reclassified on the statement of income to align expenses with the revised presentation format. The most significant adjustment is to separately disclose staff costs and employee benefits expenses. This reclassification resulted in other raw materials and other administration expenses increasing by $19 million and $10 million respectively for the three months ended March 31, 2010 and $133 million and $57 million respectively for the twelve months ended December 31, 2010.
- In accordance with IAS 37, the unwinding of the discount on provisions should be presented as a finance expense. Under Canadian GAAP, it was presented as part of depreciation and amortization. The impact of this difference is to reclassify $1 million for the three months ended March 31, 2010 and $6 million for the twelve months ended December 31, 2010 from depreciation and amortization to finance expense.

14. Supplementary annual disclosures for the twelve months ended December 31, 2010:

(a) Finance lease receivables

	Minimum lease payments		Present value of minimum lease payments	
	December 31, 2010	January 1, 2010	December 31, 2010	January 1, 2010
Amounts receivable under finance leases:				
Less than one year	$ 9	$ 9	$ 4	$ 4
Between one and five years	34	35	21	20
More than five years	78	88	64	71
Unearned finance income	(32)	(37)		
Lease payment receivable	89	95	89	95
Less current portion: (included within trade and other receivables)	4	4	4	4
	$ 85	$ 91	$ 85	$ 91

The PPA under which the Company's power generation facility located in Oxnard, California operates, expires in 2020. The average effective interest rate inherent in the lease is 9.0%.

The PPA under which the Company's power generation facility located in Kingsbridge, Ontario operates, expires in 2026 and has an effective rate inherent in the lease of 3.2%. The lease receivable contains an unguaranteed residual value of $13 million.

Finance income of $1 million was recognized in other income during the three months ended March 31, 2010.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

14. Supplementary annual disclosures for the twelve months ended December 31, 2010, continued:

(b) Intangible assets

	Alberta PPAs	CPILP PPAs	Contract rights	Customer rights	Other rights	Emission credits	Software intangibles	Total
Cost								
As at January 1, 2010	$ 140	$ 411	$ 104	$ 4	$ 56	$ 11	$ 13	$ 739
Additions from separate acquisition	-	-	-	-	17	16	6	39
Disposals	-	-	-	-	-	(8)	(3)	(11)
Foreign currency translation adjustments	-	(24)	(3)	-	-	-	-	(27)
Other changes, movements	-	-	-	-	-	-	-	-
Balance as at December 31, 2010	$ 140	$ 387	$ 101	$ 4	$ 73	$ 19	$ 16	$ 740
Accumulated Amortization								
As at January 1, 2010	$ (6)	$ (20)	$ (9)	$ -	$ -	$ (1)	$ (1)	$ (37)
Amortization	(12)	(35)	(3)	-	-	-	(2)	(52)
Impairments	-	(4)	(3)	-	-	-	-	(7)
Foreign currency translation adjustments	-	7	-	-	-	-	-	7
Balance as at December 31, 2010	$ (18)	$ (52)	$ (15)	$ -	$ -	$ (1)	$ (3)	$ (89)
Net book value								
As at January 1, 2010	$ 134	$ 391	$ 95	$ 4	$ 56	$ 10	$ 12	$ 702
As at December 31, 2010	$ 122	$ 335	$ 86	$ 4	$ 73	$ 18	$ 13	$ 651

Impairments

No impairments or reversals of impairments relating to other intangible assets were recognized during the three months ended March 31, 2010. Details of impairments recognized on transition to IFRS and for the year ended December 31, 2010 are detailed in notes 13(b) and 13(g).

Capitalized borrowing costs

Borrowing costs were not capitalized on intangible assets during the three months ended March 31, 2010 or the twelve months ended December 31, 2010.

Restrictions on assets

There are no charges over the Company's intangible assets.

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

14. Supplementary annual disclosures for the twelve months ended December 31, 2010, continued:

(c) Property, plant and equipment

	Construction work in progress	Land	Plant and equipment	Total
Cost or deemed cost				
As at January 1, 2010	$ 675	$ 68	$2,700	$3,443
Assumed on acquisition	-	-	218	218
Additions	275	-	74	349
Additions into service	(60)	-	60	-
Foreign currency translation adjustments	-	-	(37)	(37)
As at December 31, 2010	$ 890	$ 68	$3,015	$3,973
Accumulated Depreciation				
As at January 1, 2010	$ -	$ -	$ (98)	$ (98)
Depreciation	-	-	(170)	(170)
Foreign currency translation adjustments	-	-	7	7
Impairments	-	-	(36)	(36)
Other changes, movements	-	-	2	2
As at December 31, 2010	$ -	$ -	$ (295)	$ (295)
Net book value				
As at January 1, 2010	$ 675	$ 68	$2,602	$3,345
As at December 31, 2010	$ 890	$ 68	$2,720	$3,678

Impairments

No impairments or reversals of impairments on property, plant and equipment were recognized during the three months ended March 31, 2010. Details of impairments recognized on transition to IFRS and for the year ended December 31, 2010 are detailed in notes 13(b) and 13(g).

Capitalized borrowing costs

Interest capitalized to property, plant and equipment for the three months ended March 31, 2010 was $11 million. The average borrowing rate used to capitalize interest during the three months ended March 31, 2010 was 6.2% for projects financed using general borrowings. For the three months ended March 31, 2010, there were no projects financed using specific borrowings.

(d) Goodwill

	December 31, 2010
Cost	
As at January 1, 2010	$ 140
Foreign currency translation adjustments	(1)
As at December 31, 2010	$ 139
Accumulated impairment	
As at January 1, 2010	$ (12)
Impairments	(23)
As at December 31, 2010	$ (35)
Net book value	
As at January 1, 2010	$ 128
As at December 31, 2010	$ 104

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

14. Supplementary annual disclosures for the twelve months ended December 31, 2010, continued:

(d) Goodwill, continued

The aggregate carrying amounts of goodwill allocated to the Company's CGUs are as follows:

	December 31, 2010	January 1, 2010
Curtis Palmer	$ 28	$ 28
Southport	20	21
Manchief	13	13
Williams Lake	10	10
Oxnard	10	11
Nipigon	9	9
Mamquam	9	9
Kapuskasing	-	10
North Bay	-	10
Other	5	7
	$ 104	$ 128

Key assumptions used in testing recoverable amounts

The Company reviews its CGUs that contain goodwill on an annual basis to determine whether an impairment should be recognized. The last impairment review was completed in the third quarter of 2010 under a fair value less cost to sell valuation approach. The recoverable amounts of CGUs as assessed in the third quarter of 2010 and on transition to IFRS at January 1, 2010 was calculated using discounted cash flow projections consistent with the Company's long-term planning forecast, including projected contract revenues over the terms of the contracts. Other key assumptions include the following:

- The discounted cash flow approach used to estimate the fair value less cost to sell of the CGUs incorporated market place participant assumptions.
- Growth rates of nil to 2% were used to extrapolate cash flow projections beyond the ten year period covered by the long-term plan and did not exceed the long-term average growth rate of the industry.
- Pre-tax discount rates used reflect the current market assessment of the risks specific to each CGU. The discount rate was estimated based on the average percentage of a weighted average cost of capital for the industry. This rate was further adjusted to reflect the market assessment of any risk specific to the CGU for which future estimates of cash flows have not been adjusted. Discount rates ranging from 5.9% to 7.0% were applied to the cash flow projections determined in the third quarter testing of recoverable amounts (January 1, 2010 – 5.9% to 7.3%).

Impairments

No impairments were recorded in the condensed interim consolidated statement of income for the three months ended March 31, 2010. Details of impairments recognized on transition to IFRS and for the year ended December 31, 2010 are detailed in notes 13(b) and 13(g).

(Unaudited, tabular amounts in millions of Canadian dollars, except share and per share amounts)

14. Supplementary annual disclosures for the twelve months ended December 31, 2010, continued:

(e) Provisions

	December 31, 2010	January 1, 2010
Decommissioning	$ 125	$ 104
Employee benefits	30	20
Other	20	20
	175	144
Less: current portion	20	8
	$ 155	$ 136

	Decommissioning	Employee benefits	Other	Total
As at January 1, 2010	$ 104	$ 20	$ 20	$ 144
Additional liabilities incurred	20	20	7	47
Liabilities settled	(2)	(6)	-	(8)
Amounts reversed unused	-	-	(7)	(7)
Foreign currency translation adjustments	(1)	-	-	(1)
Change in discount rate	4	-	-	4
Other adjustments	-	(4)	-	(4)
As at December 31, 2010	$ 125	$ 30	$ 20	$ 175

Decommissioning provisions

The Company has recorded decommissioning provisions for its power generation plants and the Genesee coal mine as it is obliged to remove the facilities at the end of their useful lives and restore the plant and mine sites to their original condition. Decommissioning provisions for the coal mine are incurred over time as new areas are mined, and a portion of the liability is settled over time as areas are reclaimed prior to final pit reclamation.

As at December 31, 2010, the estimated undiscounted amount of cash flow required to settle the Company's decommissioning obligations was approximately $386 million, calculated using an inflation rate of 2%. The expected timing for settlement of the obligations was between 2011 and 2090, which reflected the anticipated useful lives of the different power plants. The majority of the payments to settle the obligations were expected to occur between 2022 and 2070 for the power generation plants and between 2011 and 2018 for sections of the Genesee coal mine. Rates used to calculate the carrying amount of the obligation ranged from 1.2% to 8.7%. The actual costs to settle decommissioning obligations may vary from estimates as a result of changes to contractor rates required to perform the decommissioning.

No assets have been legally restricted for settlement of these liabilities.

Other provisions

The Company holds retail and commercial natural gas customer contracts in Alberta, acquired as part of the July 1, 2009 acquisition of assets from EPCOR Utilities Inc. The future unavoidable costs of meeting the terms of these contracts are expected to exceed the economic benefits to be received under these contracts. As a result, a provision has been recorded on the consolidated statement of financial position to reflect the estimated present value of the loss on these contracts. The expected timing of settlement of these contracts range from 2011 to 2046 and the costs were discounted using risk free rates between 1.4% and 3.8%. The timing and amount of settlement of the obligation is dependent on expectations of renewal of the contracts and expectations over the forward price of gas.

15. Comparative figures:

Certain comparative Canadian GAAP figures have been reclassified to conform to the current period's presentation.